SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 222 TO FACILITY OPERATING LICENSE NO. DPR-71

AND AMENDMENT NO. 247 TO FACILITY OPERATING LICENSE NO. DPR-62

CAROLINA POWER & LIGHT COMPANY

BRUNSWICK STEAM ELECTRIC PLANT, UNITS 1 AND 2

DOCKET NOS. 50-325 AND 50-324

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1.0 OVERVIEW

1.1 Introduction

By letter dated August 9, 2001, Carolina Power & Light Company (CP&L, the licensee) submitted an amendment request to increase the licensed power from 2558 megawatts thermal (MWt) to 2923 MWt for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. This change represents an increase of approximately 15 percent above the current licensed power at BSEP, Units 1 and 2, and is considered an extended power uprate (EPU). An approximate 5-percent power uprate was authorized by the Nuclear Regulatory Commission (NRC) on November 1, 1996. The total change when completed will represent an increase of approximately 20 percent above the original rated thermal power (RTP) of 2436 MWt. The proposed amendments would also change the operating license and the technical specifications (TS) appended to the operating license to provide for implementing uprated power operation. The power uprate is planned to occur over two refueling outages because of the numerous modifications that have to be performed to achieve the 15-percent uprate.

Following the first refueling outage in March 2002 for BSEP, Unit 1, and March 2003 for BSEP, Unit 2, the licensee expects to operate at a 5- to 10-percent higher power level. The remaining uprate in power will be achieved following the second refueling outage expected to commence approximately in March 2004 for BSEP, Unit 1, and March 2005 for BSEP, Unit 2. Enclosure 2 of the initial submittal contains a list of the planned modifications.

The application was supplemented by letters dated October 17, November 1, 7, 28, and 30, December 4, 10, 17 (2 letters), and 20, 2001, January 24, February 1, 4, 13, 14, 21 (2 letters), and 25 (3 letters), March 4, 5, 7, 12, 14 (2 letters), 20, 22, and 25, and April 26 and 29, 2002. The supplemental letters contained clarifying information only, and did not change the scope of the initial application.

1.2 Background

BSEP, Units 1 and 2, are currently licensed to operate at a maximum reactor power level of 2558 MWt. The licensee, in conjunction with General Electric Company (GE), undertook a program to uprate the maximum reactor power level by approximately 15 percent to 2923 MWt, which represents an increase of approximately 20 percent above the original licensed power of 2436 MWt. At the approximately 15-percent uprated reactor power level, the generator electrical output will increase approximately 140 megawatts electric (MWe).

The BSEP, Units 1 and 2, safety analysis of the proposed EPU was provided in NEDC-33039P, “Safety Analysis Report for Brunswick Units 1 and 2 Extended Power Uprate” (PUSAR), August, 2001, prepared by General Electric Nuclear Energy (GENE). This report described the plants’ ability to operate at the higher power level and to respond to anticipated operational occurrence transient and accident conditions as designed and analyzed. The licensee also evaluated the effect of the increased thermal power on the capability and performance of systems, structures, and components important to safe operation of the plant.

In general, the licensee’s plant-specific engineering evaluations supporting the power uprate were performed in accordance with guidance contained in the GE licensing topical report (LTR) NEDC-32424P, “Generic Guidelines for General Electric Boiling Water Reactor (BWR)

Extended Power Uprate (ELTR1)." This topical report was previously reviewed and endorsed by the NRC staff. For some items, bounding analyses and evaluations provided in GE LTR, NEDC-32523P, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate (ELTR2)," were cited. The NRC staff has also approved ELTR2. The ELTR2 generic evaluations assume (a) a 20-percent increase in the thermal power, (b) an increase in operating dome pressure up to 1,095 psia, (c) a reactor coolant temperature increase to 556 degrees Fahrenheit, and (d) a steam and feedwater flow increase of about 24 percent.

In general, the licensee followed the guidelines in ELTR1 and ELTR2 for the BSEP, Units 1 and 2, EPU evaluation. However, the BSEP, Units 1 and 2, EPU safety analysis deviates from the ELTR1 and ELTR2 guidelines in the stability analyses, the loss-of-coolant accident (LOCA) analysis, transient analyses, and testing.[

.] The deviations are discussed in the following areas:

Thermal Limits Assessment (Section 2.2)
Stability (Section 2.4)
Emergency core cooling system (ECCS) performance (Section 4.3)
Reactor transients (Section 9.1)
Testing (10.4)

1.3 Approach

An increase in the electrical output of a BWR is accomplished primarily by supplying a higher steam flow to the turbine generator. Most GE BWRs were originally licensed with the ability to accommodate steam flow rates at least 5 percent above the original rating. In addition, improved analytical techniques and computer codes, operating experience, and improved fuel designs have resulted in significant increases in the operating margins above the licensing limits. The higher margins, combined with the as-designed equipment, system, and component capabilities, have allowed many BWRs, including BSEP, Units 1 and 2, to increase their thermal power ratings by 5 percent (stretch uprate) up to the current rated thermal power (CRTP) without modifying any nuclear steam supply system (NSSS) hardware.

The approach to achieving EPU consists of:

(1) an increase in the core thermal power with a more uniform power distribution to generate higher steam flow,

(2) a corresponding increase in the feedwater flow,

(3) no increase in the maximum core flow, and

(4) reactor operation primarily along the maximum extended load line limit analysis (MELLLA) rod/flow lines.

To increase the steam generation without increasing the maximum core flow, the licensee needs to implement core design changes, including flatter radial power distribution, higher GE 14 batch fractions in the core, and changes in enrichment of the GE 14 fuel. The EPU operation would increase the licensed operating domain by extending along the MELLLA rod line up to the EPU power level, which corresponds to the minimum core flow state point. MELLLA was implemented on October 23, 1990, for BSEP, Unit 1, and on October 12, 1989, for BSEP Unit 2. The power/flow map would extend the maximum achievable core flow at the EPU power level without exceeding the maximum licensed thermal power. This approach is consistent with the NRC-approved BWR EPU guidelines that are in ELTR1 and ELTR2.

1.4 Staff Evaluation

The NRC staff's review of the BSEP Units 1 and 2 EPU amendment request used applicable rules, regulatory guides, Standard Review Plan (SRP) sections, and NRC staff positions on the topics being evaluated. Additionally, the NRC staff evaluated the EPU application for conformance with the generic BWR EPU program as defined in topical reports ELTR1 and ELTR2. The NRC-accepted ELTR1 and ELTR2 provide appropriate guidelines for the EPU applications. The licensee took exceptions to certain previously approved generic positions in these topical reports. The NRC staff's conclusions about the acceptability of the exceptions are given in the applicable sections of this SE.

The scope of the NRC staff's review for the BSEP Units 1 and 2 EPU request included "lessons learned" from past power uprate amendment reviews and the recommendations of the Maine Yankee Lessons Learned Task Group (SECY-97-042, "Response to OIG Event Inquiry 96-04S Regarding Maine Yankee," February 18, 1997). The task group's main findings centered on the use and applicability of the computer codes and analytical methods used for the power uprate evaluations. Table 1-3 of the PUSAR listed computer codes in each of the BSEP EPU analyses and the corresponding NRC-approval status for the use of the code for the particular application. The table indicated that all the applicable codes were reviewed and approved by the NRC for the corresponding analysis, except for ISCOR and TASC (for ECCS-LOCA). The transient critical power code (TASC) has since been approved by the NRC staff on March 13, 2002.

The ISCOR application is discussed in Section 4 of NEDE-24011P-A, General Electric Standard Application for Reactor Fuel (GESTARII)," which is NRC approved. However, the code is used with no explicit NRC approval in many safety and accident analyses. In a response to the NRC staff's request for additional information (RAI), the licensee stated that ISCOR is used in the following areas of the EPU evaluation: core and bundle heat balances, bundle flows, initial condition thermal limits, loss coefficients, bypass heating and flow fractions, direct moderator heating, pressure drop for the core and bundles, and/or detailed pressure drop within the fuel bundle. Moreover, the licensee stated that all the applications of the ISCOR code are consistent with the basis described in the NRC-approved GE licensing methodology topical report, NEDE-24011-A. The licensee also identified other approved applications or documents that described the use of ISCOR. The licensee concluded that explicit NRC approval was not deemed necessary for essentially the same use of this code for different analyses.

ISCOR is used to establish the initial steady-state thermal-hydraulic condition of the flow through the core and the code's accuracy could impact the results of the safety analyses. The NRC staff recognizes that, although ISCOR was not explicitly approved, (1) the use of the code is described in other NRC-approved applications, including the GE licensing document GESTAR II, (2) the code is also currently used for reload analysis for all operating BWRs using GE fuel and application of the code is not unique to BSEP EPU analyses, and (3) there is no evidence of inaccuracies in the results obtained using ISCOR. Therefore, the NRC staff accepts the use of ISCOR for the BSEP EPU analysis, since the models used in the code are described in the GE licensing document (NEDE-24011P-A) previously reviewed and approved by the NRC.

The BSEP Units 1 and 2 cores consist of GE 13 (9X9 design) and GE 14 (10X10 design) fuel types. The BSEP Unit 2 core also contains Siemens Atrium 10 lead use assemblies, currently scheduled to be removed during the spring 2005 refueling outage. The licensee stated that these assemblies are designed to be mechanically, neutronically, and thermal-hydraulically compatible with the existing GE reload fuel. Since these assemblies are compatible with the GE fuel, the licensee will use the operating limits of the GE fuel to establish the specific operating limits of these assemblies. In addition, the licensee will not load and operate these assemblies as the limiting fuel assemblies in the core and these assemblies will also be monitored. The GE 14 fuel was introduced into the BSEP Unit 1 core in Reload 13 Cycle 14. For BSEP Unit 2, GE 14 fuel was introduced into the core in 2001 during the Cycle 15 reload. The two units have almost identical system geometry, reactor protection system configuration, and mitigation functions. They also exhibit similar thermal-hydraulic and transient response characteristics. The units differ in two main areas: Unit 2 fuel has smaller side entry orifices with an associated higher pressure drop, which affects the core flow, and (2) Units 1 and 2 have different turbine bypass capacities of 20.6 percent and 69.6 percent of the EPU rated steam flow, respectively. These differences are accounted for in the safety analyses either by the use of plant-specific values in the cases where separate analyses are performed for each of the units or by the use of bounding values in cases where one bounding analysis is used for both units. For instance, the ECCS-LOCA analyses are based on BSEP Unit 2, since the higher core flow resistance in BSEP Unit 2 affects the ECCS-LOCA response. The ATWS analysis response is affected by the turbine bypass capacity and this is discussed further in Section 9.3.1 of this Safety Evaluation (SE).

Section 5.0 of the BSEP Units 1 and 2 TS documents the LTRs that specify the codes and methodologies used for performing the safety analyses. All of the BSEP Units 1 and 2 safety analyses are performed in accordance with the GE analytical and licensing methods specified in GESTAR II. The GE licensing methodology requires that all limiting anticipated operational occurrence (AOO) and accident analyses be analyzed or confirmed on a cycle-specific basis during the reload analysis.

2.0 REACTOR CORE AND FUEL PERFORMANCE

The core thermal-hydraulic design and fuel performance characteristics are evaluated for each reload fuel cycle. The following sections address the effect of the EPU on fuel design performance, thermal limits, the power/flow map, and stability.

2.1 Fuel Design and Operation

Fuel bundles are designed to ensure that (a) they are not damaged during normal steady-state operation and AOOs; (b) any damage to them will not be so severe as to prevent control rod insertion when required; (c) the number of fuel rod failures during accidents is not underestimated; and (d) the ability to cool the core is always maintained. For each fuel vendor, use of NRC-approved fuel design acceptance criteria and analysis methodologies assures that the fuel bundles perform in a manner that is consistent with the objectives of Sections 4.2 and 4.3 of the SRP and the applicable general design criteria (GDC) of 10 CFR Part 50, Appendix A. The fuel vendors perform thermal-mechanical, thermal-hydraulic, neutronic, and material analyses to ensure that the fuel system design can meet the fuel design limits during steady-state, AOO, or accident conditions.

EPU operation would increase the average power density proportionally to the power increase, but the average power density would remain within the power density of other GE-supplied BWR plants. The plant is currently operating at an average bundle power of 4.6 MW/bundle. The average bundle power for the EPU operation for both units is 5.2 MW/bundle (2923/560), although the actual bundle power depends, in part, on the fuel bundle design, the bundle exposure, and the operating conditions. The increased operating power would affect the operating flexibility and the reactivity characteristics of the core. EPU operation, without changes in the cycle length, would require the core to produce more energy per cycle. Therefore, the licensee plans to use larger fresh batch sizes of the GE14 fuel, using custom-built GE14 fuel containing different enrichment and gadolinia burnable poison. Since the average bundle power increases and the thermal limits remain the same, a flatter radial power distribution is used to achieve higher steam generation. The higher batch sizes and the flatter power distribution result in more high power bundles in the core for the EPU operation relative to the current core design.

Limits on the fuel rod linear heat generation rate (LHGR) will ensure compliance with the fuel thermal-mechanical design bases. The thermal-hydraulic design and the operating limits ensure an acceptably low probability of boiling-transition-induced fuel cladding failure in the core in the event of an AOO. Limits on the fuel average planar linear heat generation rates ensure that both the peak cladding temperature limits for LOCA and fuel thermal-mechanical design bases are met. Cycle-specific analysis will be performed for each unit every reload to ensure the reload core performance during the cycle maintains acceptable margin between the licensing limits and the corresponding operating limits. In addition, the core design methods used to analyze the core and fuel performance are based on the NRC-approved methodology and codes specified in GESTAR II.

During the on-site audit, the NRC staff reviewed the BSEP Unit 1 Cycle 14 EPU reload analysis performed at the EPU power level in order to understand the EPU core design relative to the current core design and the impact of the EPU core design on the thermal limits. The BSEP Unit 1 Cycle 14 core design confirmed that the core radial power distribution would be flatter, with high powered bundles near the periphery of the core. The enrichment and burnable poisons varied for the GE 14 fuel and the fresh batch fraction would be increased to achieve the EPU energy requirements. The licensee performed the limiting transient and accident analyses to establish the thermal limits. The BSEP Unit 1 Cycle 14 reload analysis demonstrated that the unit can operate at the EPU power level while maintaining the fuel design limits. Therefore, based the information presented in the PUSAR, the results of the NRC staff's audit, the responses to the NRC staff's RAIs, and the use of the NRC-approved methodology and codes, the NRC staff concludes that the licensee's EPU fuel design and operation evaluations are acceptable.

2.2 Thermal Limits Assessment

2.2.1 Minimum Critical Power Ratio (MCPR) Operating Limit

The safety limit minimum critical power ratio (SLMCPR) ensures that 99.9 percent of the fuel rods are protected from boiling transition during steady-state operation. The operating limit minimum critical power ratio (OLMCPR) assures that the SLMCPR will not be exceeded as a result of an AOO.

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In accordance with the GESTAR II licensing methodology, CP&L performed the cycle-specific reload analyses for Unit 1, Cycle 14. Due to the schedule for the balance-of-plant (BOP) modifications, the licensee intends to uprate Unit 1 in phases and operate Unit 1 at the EPU power level only after loading additional GE14 fuel in March 2004, during Cycle 15, Reload 14 refueling outage. The cycle-specific reload analysis for Cycle 15 will support the EPU cycle operation as required.

However, CP&L performed the Cycle 14 reload analysis at both the CRTP and the EPU power level to support the first phase of the power uprate. The licensee performed the transient and accident analyses used to establish the OLMCPR to ensure the SLMCPR would not be violated during an AOO or for the events used to establish the OLMCPR. CP&L also submitted an amendment request (ADAMS Accession No. ML012690334, September 18, 2001) proposing to implement the Unit 1 Cycle 14 SLMCPR in the BSEP Unit 1 TS. The NRC staff audited the Cycle 14 core design and the reload safety analysis used to establish the SLMCPR and the OLMCPR change for Unit 1, Cycle 14. The key parameters used by GE to quantify the bundle-to-bundle power distribution and the pin-to-pin power distribution indicate that both the radial power distribution and the pin-to-pin power distribution would be flatter. The flatness of the power distribution was compared against the Unit 1 core design for Cycle 13. The power distribution is one of the parameters that affect the SLMCPR and the Unit 1 Cycle 14 SLMCPR increased by 0.02. This is within the range predicted by GE for the constant pressure power uprate impact on the SLMCPR, with no other changes associated with it. The licensee calculated an OLMCPR of 1.12 for two recirculation loop operation (TLO) for Unit 1 Cycle 14 core design at the CRTP and EPU power level. The OLMCPR at the higher power level did not increase because of the plant's response during the most limiting transient. This is discussed with more detail in Section 9.1 of this document. The NRC staff also reviewed the supplemental reload licensing report that documents the results of the Unit 1, Cycle 14 reload safety analyses performed at the EPU power level and verified that the licensee had performed the reload transient analyses required to establish the OLMCPR.

Due to the similarity between the units and the small changes in OLMCPR seen in previous EPU evaluations, the Unit 1, Cycle 14 reload analysis demonstrates the feasibility of the EPU operation for Unit 2. The differences in the units' turbine bypass capacity and in the core inlet orifice dimensions will be modeled in the cycle-specific evaluations for each unit.

1. [

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2. The OLMCPR will be calculated on a cycle-specific reload using the actual core design parameters. [

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3. The OLMCPR will be determined based on NRC-approved codes and licensing methodology specified in GESTAR II,

4. The cycle-specific OLMCPR values will be documented in the core operating limit report (COLR) and the supplemental reload licensing report (SRLR),

5. The licensee would have to apply a penalty or de-rate to ensure the SLMCPR would not be exceeded as a result of an AOO if the EPU core design cannot demonstrate adequate safety or operating MCPR margin, and,

6. The BSEP Unit 1, Cycle 14 reload analysis and OLMCPR calculations provide adequate assurance that the Unit 2 OLMCPR values would be within the Unit 1 range due to the similarity between the two units.

In a March 11, 1999, SE, the NRC staff approved Amendment 25 to GESTAR, which replaced the generic equilibrium core safety limit MCPR evaluation with the cycle-specific evaluation based on specific bundle design and actual core loading. The proposed changes in Amendment 25 stemmed, in part, from NRC concerns (NRC Inspection Report Nos.9990003/95-01 and 99900003/96-01) about the conservatism of using bounding equilibrium core SLMCPR values. In addition, the SLMCPR is specified in the BSEP TS and any changes to the SLMCPR require an amendment request for NRC approval. Consequently, the licensee will submit an amendment request for EPU operations for each unit if the TS SLMCPR does not bound the calculated cycle-specific SLMCPR. Therefore, the NRC staff finds [ ] the SLMCPR calculation to [ ] to be acceptable.

The NRC staff concludes that the licensee has demonstrated that BSEP Units 1 and 2 can operate at the EPU power level, while maintaining the SLMCPRs and OLMCPRs. The NRC staff concludes that the GE licensing methodology and the TS requirements will ensure that limits are determined based on the core design and the operating conditions for each cycle.

2.2.2 Maximum Average Planar Heat Generation Rate (MAPLHGR) and Maximum LHGR Operating Limits

The MAPLHGR limit is selected to ensure that the peak cladding temperature during LOCA does not exceed the 2200 F and the operating maximum LHGR does not exceed the LHGR limit. The licensee stated that experience from other BWR power uprates indicates that no significant change in the operating limits is expected due to EPU operation and the MAPLHGR and LHGR limits will be maintained. As discussed in Section 4.3 of this SE, the licensee performed [ ] ECCS-LOCA evaluations, based on a representative GE-14 equilibrium core, operating at the EPU power level. The licensee stated that the ECCS-LOCA analysis showed that no change to the MAPLHGR or the LHGR limits is required due to the increased core thermal power associated with the EPU. For every new fuel type, the fuel vendors perform ECCS-LOCA analyses to confirm compliance with the ECCS-LOCA acceptance criteria. For every reload, licensees confirm that the ECCS-LOCA MAPLHGR bounds the exposure-dependent MAPLHGR for the fuel cycle.

During the audit, the NRC staff reviewed how the MAPLHGR curve is derived and asked GE to explain how the MAPLHGR and maximum LHGR will be maintained for mixed core of GE13 and GE14 fuels for the EPU operation. The NRC staff asked GE to provide the curves for EPU and pre-EPU conditions if there are differences between the MAPLHGR or LHGR curves for the EPU operation.

For each fuel design, GE establishes a peak LHGR curve and a MAPLHGR curve that is derived from the LHGR. These two curves form the basis for analyzing all the requirements of thermal-mechanical, thermal-hydraulic and ECCS analyses. During the Brunswick audit, the NRC staff discovered that the LHGRs of the GE13 and GE14 fuel used for the BSEP Unit 1 core design were different from the original GE14 and GE13 design curves. In an RAI response, the licensee stated that for the BSEP fuel, a detailed thermal-mechanical analysis was performed for each set of limits to demonstrate compliance with Amendment 22 of NEDE-24011-P-A. The licensee presented the LHGR curves of GE13 and GE14 fuel for the Brunswick core design, which showed slight variations from the original design curves for the fuel bundles. For the GE13 and GE14 fuel designs, the LHGR and MAPLHGR limits are specified in NEDE-32198P, "GE13 compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," and NEDC-32868P, Revision 1, "GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," respectively. Since the BSEP LHGR versus exposure curves for the GE14 and GE13 curves remain bounded by the reference fuel design curves and the fuel design is based on an NRC-approved process, the NRC staff concluded that the LHGR and MAPLHGR limits are acceptable for BSEP Units 1 and 2 EPU operation. Therefore, the NRC staff finds that the licensee complied with the requirements specified in the NRC-approved licensing methodology in GESTAR II in establishing the fuel design limits.

The licensee is required to ensure that plant operation is in compliance with the cycle-specific thermal limits (SLMCPR, OLMCPR, MAPLHGR, and LHGR). The thermal limits are documented in the BSEP cycle-specific COLR as required by Section 5 of the BSEP Units 1 and 2 TS. In addition, while EPU operation may result in a small change in fuel burn up, the licensee is not permitted to exceed the NRC-approved burnup limits described in approved Topical Reports as referenced in the TS. To meet the energy requirements for the EPU power level, the licensee projects that a larger GE14 batch fraction may be needed for the future reloads. Therefore, for the EPU core, the fuel burnup may be lower relative to the core design for the CRTP. Based on this review, the NRC staff finds that the licensee has appropriately considered the potential effects of EPU operation on the fuel design limits. The NRC staff concludes that the current thermal limits assessment is acceptable for BSEP Units 1 and 2 operation.

2.3 <u>Reactivity Characteristics</u>

The licensee stated that operation at higher power could reduce the hot excess reactivity, typically by about 0.2 to 0.3 percent Δk for each 5-percent power increase. The loss of reactivity is not expected to affect the ability to manage the power distribution needed to meet the target power through the cycle. The lower hot excess reactivity can result in an earlier all-rod-out condition during the operating cycle. However, through reload fuel cycle-specific core analyses, the core can be designed with sufficient excess reactivity to maintain the fuel cycle length. Core design changes that increase the hot reactivity may also result in less hot-to-cold reactivity difference, reducing the available cold shutdown margin. The licensee stated that the EPU core design would account for the loss of margin and, if necessary, a fuel bundle design with improved shutdown margin characteristics could be used for future cycles. The licensee added that the reload core analysis would ensure that the minimum shutdown margin requirements were met for each core design and that the current design and TS cold shutdown margin will be met. Standby liquid control (SLC) shutdown margin changes (increased boron concentration) are discussed in Section 6.5.

The licensee is required to design the core with sufficient shutdown margin to meet the BSEP Units 1 and 2 TS cold shutdown requirement. This requirement remains the same for the EPU core design. Therefore, the NRC staff finds that the licensee's evaluation of the impact of the EPU operation on the reactivity characteristics is acceptable.

2.3.1 Power/Flow Operating Map

The BSEP units are currently licensed to operate along the MELLLA upper boundary rod line up to the CRTP of 2558 MWt (105% of the ORTP), with an operating window of 81 percent to 104.5 percent core flow at the CRTP. Figure 2-1 of the PUSAR shows the proposed operating domain for BSEP Units 1 and 2 for the EPU operation. In general, the power/flow map defines the licensed operating domain that a BWR plant is analyzed to operate within. The safety analyses and the equipment performance evaluations performed for BSEP Units 1 and 2 support the operation of the units within the specified boundaries in the proposed power/flow map shown in Figure 2-1 of the PUSAR.

The licensee proposed to define the EPU operating domain by (a) the MELLLA upper boundary line extended up to the EPU rated thermal power, (b) the EPU power level corresponding to 120 percent of the ORTP, and (c) the existing increased core flow (ICF) line of 104.5% at the CRTP continued vertically up to the EPU power. The licensee stated that the power/flow map changes incorporated in Figure 2-1 of the PUSAR are consistent with the changes shown in Figure 5-1 of ELTR1, with the ICF held constant to the maximum core flow value established by the 105% power uprate. The licensee stated that the power/flow boundaries define an increase in the TLO operating domain above the ORTP, but there would be no change in the single recirculation loop operation (SLO) operating domain in terms of megawatts versus flow.

The power/flow map in Figure 2-1 is intended to be representative of both units, although there are some minor differences in the achievable core flow for the two units due to the smaller core inlet orifices for Unit 2. In Section 3.4, "Reactor Recirculation System," of the PUSAR, the licensee stated that for BSEP 2 the actual core flow is limited to less than 104.5% unless modifications to the recirculation system are made, which may affect the fuel cycle management but will not prevent operation at the EPU RTP. Therefore, the power/flow map in Figure 2-1 does not represent the achievable operating window at the EPU power level for both units.

In an RAI response, the licensee stated that the power/flow map is a licensing region that defines the boundaries inside which the operation of the plant has been analyzed and demonstrated to meet all applicable fuel and system design criteria. The EPU licensing calculations support ICF up to 104.5% at 2923 MWt for both units. The licensee stated that the EPU calculations, assuming clean, as-built conditions, indicate that at the full EPU power level, the recirculation pumps will deliver about 1.8% less flow, which corresponds to an expected maximum ICF flow for Unit 2 of 102.3%. CP&L pointed out that the inability of Unit 2 to achieve the ICF flow has no adverse safety consequences, but it could reduce the effectiveness of fuel utilization slightly. The licensee added that Unit 1 can achieve 104.5% core flow.

From the on-site review of the recirculation system and the licensee's RAI response, it is the NRC staff's opinion that both BSEP units may not be able to achieve the maximum core flow indicated on the power/flow map in Figure 2-1. The achievable ICF values cited by the licensee are based on clean, as-designed conditions, which do not account for additional losses due to crud build-up in the jet pumps. The core flow resistance may also be higher for the actual EPU core design with more high-powered bundles in the core. Therefore, the power/flow map represents the licensed analyzed boundary and not the actual operating range that units may achieve. However, AOOs and accident analyses are evaluated at the most limiting conditions for the following statepoints: (1) minimum core flow at the EPU power level, (2) maximum licensed core flow at the rated power or at 102% power, and (3) at the offrated power and flow conditions along the MELLLA boundary. With the extension of the MELLLA boundary to the EPU power level, BSEP 1 and 2 minimum core flow at the EPU power level changes from 81 percent core flow at the CRTP to 99 percent core flow at EPU power level. The licensee will normally operate BSEP 1 and 2 at the minimum CF at the rated EPU power level statepoint (99% CF, 2923 MWt) and operation would be extended to the ICF region near the end-of-cycle. If BSEP 1 and 2 do not achieve the minimum CF statepoint at the EPU power level, the units would be at a lower power level along the analyzed MELLLA upper boundary. In addition, since the applicable EPU safety analyses are based on the 104.5% ICF condition, the safety analyses at this statepoint would bound the achievable ICF statepoint for BSEP Units 1 and 2. Therefore, the NRC staff concludes that the proposed power/flow map in Figure 2-1, which represents the licensed operating domain, but not the achievable operating domain, supports the EPU operation for both units of BSEP.

2.4 <u>Stability</u>

The long-term stability solutions for BWRs are discussed in NEDO-31960-A, “BWR Owners' Group Long-Term Stability Solutions Licensing Methodology,” published in November 1995. BSEP Units 1 and 2 previously relied on the reactor stability Long-Term Solution Enhanced Option I-A (E1-A). The NRC generically approved the Option III long-term stability solution methodology in NEDC-32410, "Nuclear Measurement Analysis and Control Power Range Neutron Monitoring (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," published in October 1995. CP&L proposed to replace the Enhanced Option I-A solution with the reactor stability Long-Term Solution, Option III in complying with the requirements of GDC-12. Implementation of the Option III long-term stability solution was approved by the NRC for BSEP Units 1 and 2 in Amendments 217 and 243, respectively (ADAMS Accession No. ML020720742). This includes modifying the power range monitoring system (PRNM) to integrate the Option III stability solution Oscillation Power Range Monitor (OPRM) upscale trip function into the system electronics. The OPRM is a monitoring and protection system that will detect a thermal-hydraulic instability, provide an alarm on small oscillation magnitudes, and initiate an automatic suppression function to suppress an oscillation prior to exceeding the safety limit. The Option III stability algorithm evaluates the OPRM signals to determine when the signal is becoming sufficiently periodic and large to warrant a reactor scram. The OPRM trip function initiates a reactor scram only when the plant is operating in the Option III OPRM Trip Enable Region. The Option III Trip Enable Region will be defined in the BSEP Units 1 and 2 TS, in the plant procedures, and in the power/flow map. Figure 2-3 of the PUSAR shows the Trip Enable region re-scaled to maintain the pre-EPU absolute power and flow. The implementation of the Option III long-term stability solution has been completed for Unit 1, and will be completed for Unit 2 during the spring 2003 refueling outage.

The licensee has taken exception to one of the generic guidelines in ELTR2, regarding thermal-hydraulic stability. In the NRC staff SE on ELTR2, Section 3.2.2, “Long-Term Solution,” states: “The prevention and detection/suppression features of the long term stability solutions are either demonstrated to be unaffected by power uprate or are modified and validated in accordance with the solution methodology." The NRC staff's SE on ELTR2 states that the thermal-hydraulic stability monitoring system should be validated in accordance with the generic solution methodology using a representative equilibrium core design and included in the application for EPU.

In the BSEP Units 1and 2 PUSAR, CP&L proposed to eliminate the setpoint calculations based on a representative equilibrium core and instead rely on the cycle-specific setpoints calculations. In establishing the OPRM setpoints, the acceptable low setpoints are determined such that expected plant evolutions will not result in an OPRM system trip, and the setpoints are confirmed to provide margin to the MCPR safety limit. This is done on a cycle-specific basis. The NRC staff concludes that this approach is acceptable for the following reasons:

1. The NRC has approved the reactor stability Long-Term Solution, Option III specified in NEDO-31960-A, published in November 1995.

2. [ ]

3. The licensee will perform the OPRM setpoints calculations as specified in the NRC-approved licensing document on a cycle-specific basis for each particular reload core. This evaluation will be done before the EPU is implemented and will be documented in the reload analysis.

CP&L has calculated the OPRM setpoints for the BSEP Unit 1, Cycle 14 core at the EPU level, in accordance with NEDO-32465-A, "Reactor Stability Detect and Suppress Solution Licensing Basis Methodology for Reload Application." The BSEP Unit 1, Cycle 14 SRLR documents the OPRM amplitude setpoints that will provide the MCPR protection, notwithstanding the 10 CFR Part 21 reporting applicability of the generic delta critical power ratio over initial critical power ratio versus oscillation magnitude (DIVOM) curve.

CP&L plans to have the OPRM trip function fully operational during the first startup following installation of the new PRNM system, which corresponds to the March 2002 refueling outage for Unit 1. Based on figure-of-merit calculations, CP&L has determined that the existing generic regional mode DIVOM curve is applicable to BSEP Unit 1. The figure-of-merit is described in GE Nuclear Energy letters to the NRC dated June 29, 2001, and August 31, 2001. Since the generic DIVOM curve is applicable, the OPRM trip function is operable and enabled for Unit 1 and there is assurance that Option III stability trip system setpoints will provide MCPR safety limit protection. Implementation of the Option III stability solution for Unit 2 will be completed in spring 2003.

In the ELTR2 SER, the NRC staff concluded that the existing stability corrective actions are applicable or adaptable to EPU operation. The ICA stability boundaries are kept the same in terms of absolute core power and flow for EPU. The power levels, reported as a percentage of rated power, are rescaled to the uprated power. Since the DIVOM curve Part 21 issue has not yet been resolved by the Boiling Water Reactor Owners Group (BWROG), the ICA operation, if necessary for BSEP Unit 1, provides an acceptable alternative option to control instabilities, with the OPRM monitoring system providing early warning.

Based on reasons discussed above, the NRC staff accepts the licensee's approach to meeting regulatory requirements for reactor stability for BSEP Units 1 and 2 operation at the EPU power levels.

2.5 Reactivity Control

2.5.1 Control Rod Drive (CRD) System Performance

The CRD system controls gross changes in core reactivity by positioning neutron-absorbing control rods within the reactor. The CRD system is also required to scram the reactor by rapidly inserting withdrawn rods into the core. The scram rod insertion and withdrawal functions of the CRD system depend on the operating reactor pressure and the pressure difference between the CRD system hydraulic control unit (HCU), and the reactor vessel bottom head pressure.

The licensee stated that since there is no increase in the reactor operating pressure, the CRD scram performance and compliance with the current TS scram requirements are not affected by operation at the EPU power level. The CRD system was generically evaluated in Section 5.6.3 and J.2.3.3 of ELTR1 and Section 4.4 of Supplement 1 to ELTR2. The licensee performed confirmatory evaluations of the performance of the CRD system at the EPU conditions based on a reactor dome pressure of 1030 psig, with 35 psid added to account for the static head of water in the vessel.

For CRD insertion and withdrawal, the required nominal pressure between the HCU and the vessel bottom head is 260 psid. The licensee evaluated the CRD pump capability and determined that the CRD pumps have sufficient capacity to provide the required pressure difference for operation at the EPU conditions. The licensee also evaluated the required CRD cooling and drive flows for EPU operation and stated that the cooling and drive flows are assured by the automatic operation of the CRD system flow control valve, which would compensate for any changes in the reactor pressure. The licensee stated that the BSEP CRD operating data indicate that the CRD pumps and the CRD system flow control valves have sufficient margin to ensure the system can operate normally under the EPU conditions.

The licensee determined that the operation of the BSEP Units 1 and 2 CRD system is consistent with the generic evaluations in ELTR1 and ELTR2 and that the CRD system is, therefore, capable of performing its design functions of rapid rod insertion (scram) and rod positioning (insertion/withdrawal) during EPU operation. In the previous power stretch uprate, the licensee increased the reactor dome pressure, but this is not significant, because the reactor pressure assists the scram function. During scrams at low reactor pressure, the accumulator provides the pressure for the scram. However, at higher power, such as during isolation events, the accumulator pressure may not be sufficient due to the system losses. The CRD system is designed to use the reactor pressure to assist the scram for high reactor pressure scrams. In addition, scram time testing verifies the scram time for individual control rods to ensure that the rods scram within the times assumed in the safety analyses.

For the reasons set forth above, and consistent with the previous NRC evaluations of ELTR1 and ELTR2, the NRC staff agrees with the licensee's determinations that the CRD will continue to meet its design basis and performance requirements at uprated power conditions.

2.5.2 Control Rod Drive System Structural Evaluation

The licensee indicated that the CRD mechanisms (CRDMs) have been designed in accordance with the Code of record, the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* Section III, 1968 Edition up to and including the Winter 1970 addenda for BSEP Unit 1, and 1968 Edition with addenda up to and including the Winter 1968 addenda for BSEP Unit 2. The components of the CRDM, which form part of the primary pressure boundary, have been designed for a bottom head pressure of 1250 psig, which is higher than the analytical limit of 1131 psig for the reactor bottom head pressure.

The licensee's evaluation indicated that the maximum calculated stress for the CRDM is less than the allowable stress limit. The analysis of the CRDM also showed that the calculated maximum cumulative usage factor (CUF) for the limiting CRD location is 0.15, which is less than the Code-allowable CUF limit of 1.0. This is acceptable to the NRC staff.

On the basis of its review, the NRC staff finds that the CRDM will continue to meet its design basis and performance requirements at uprated power conditions.

3.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

3.1 Nuclear System Pressure Relief

The safety/relief valves (SRVs) provide overpressure protection for the NSSS, preventing failure of the nuclear system pressure boundary and uncontrolled release of fission products. BSEP Units 1 and 2 have 11 SRVs each, which are piped to the suppression pool. These SRVs, together with the reactor scram function, provide overpressure protection during abnormal operational transients. The SRV setpoints are established to provide the overpressure protection function, while ensuring that there is adequate pressure difference (simmer margin) between the reactor operating pressure and the SRV actuation setpoints. The setpoints are also selected to be high enough to prevent unnecessary SRV actuations during normal plant maneuvers.

For EPU operation, the licensee will not change the SRV setpoints, because the maximum operating dome pressure will not change. Table 5-1 of the PUSAR lists the analytical limit setpoints for the BSEP Units 1 and 2 SRVs. The two units have 11 SRVs each, with 4 SRVs actuating at 1164 psig, 4 SRVs actuating at 1174 psig and 3 SRVs actuating at 1184 psig, with a 3-percent upper limit tolerance included. The TS requires the SRV setpoint tolerances to be monitored and the licensee stated that the in-service surveillance testing of the BSEP units has not shown a significant propensity for high setpoint drift greater than 3 percent. The licensee reported that out of 55 SRV tests, based on the "as found" setpoint lift tests performed between 1997 and 2001, only four SRVs exceeded their setpoints by greater than 3 percent. The BSEP data cited by the licensee indicate that the high setpoint drift of 3 percent used in the safety analyses is adequate.

The licensee evaluated the capabilities of the SRVs to provide overpressure protection based on the current setpoints and tolerances for operation at the EPU power level and determined that the nuclear boiler pressure relief system has the capability to provide sufficient overpressure protection. The licensee also stated that the EPU evaluation is consistent with the generic evaluations and discussions in Section 5.6.8 of ELTR1 and Section 4.6 of ELTR2.

Since the licensee performed the limiting ASME Code overpressure analyses (discussed in Section 3.2) based on 102 percent of the EPU power level, the current SRVs setpoints, and the upper tolerance limits, the NRC staff finds that the SRVs will have sufficient capacity to handle the increased steam flow associated with the EPU operation. BSEP Units 1 and 2 are licensed for one SRV out of service (OOS), and this is assumed in the applicable transient and accident analyses. In addition, the ASME overpressure analyses are performed on a cycle-specific basis. Therefore, the capability of the SRVs to ensure ASME overpressure protection will be confirmed in each subsequent reload analysis. This practice is consistent with current approved methods and is acceptable to the NRC staff.

3.1.1 SRV Setpoint Tolerance

The licensee performed the overpressure protection analysis at the uprated power condition using the upper tolerance limits of the valve setpoints. The peak RPV dome pressure was calculated at 1306 psig (1335 psig vessel bottom pressure). This peak vessel pressure remains below the ASME allowable of 1375 psig (110% of design pressure) and safety-related SRV operability is not affected by the proposed power uprate. Furthermore, the maximum operating reactor dome pressure remains unchanged for the BSEP power uprate. Consequently, the licensee concluded that the SRV setpoints and analytical limits are not affected by the proposed power uprate, and that the SRV loads for the SRV discharge line piping will remain unchanged. The NRC staff agrees with the licensee's conclusion that the SRVs and the SRV discharge piping will continue to maintain their structural integrity and provide sufficient overpressure protection to accommodate the proposed power uprate.

3.2 Reactor Overpressure Protection Analysis

The design pressure of the reactor vessel and reactor coolant pressure boundary (RCPB) remains at 1250 psig. The ASME Code allowable peak pressure for the reactor vessel and the RCPB is 1375 psig (110 percent of the design pressure of 1250 psig), which is the acceptance limit for pressurization events. The most limiting pressurization transient is analyzed on a cycle-specific basis and this approach would be applicable for each EPU reload cycle. Section 5.5.1.4 and Appendix E of ELTR1 evaluated the ASME overpressure analysis in support of a 20-percent power increase. The licensee analyzed the MSIV closure event based on an initial dome pressure of 1045 psig, at 102 percent of the EPU power level, with two SRVs out of service. The MSIV direct valve position signal scram was assumed to fail and the reactor scrams at a high-flux signal. The MSIV closure event resulted in a maximum reactor dome pressure of 1306 psig, which corresponds to a vessel bottom head pressure of 1335 psig. Therefore, the peak calculated vessel pressure (1335 psig) remains below the ASME limit of 1375 psig and the dome pressure remains below the TS 1325 psig safety limit. The NRC staff-approved evaluation model, ODYN, was used for the analysis. The licensee determined that there is no decrease in safety margin. Figure 3-1 of the PUSAR provided the EPU ASME overpressure results.

The NRC staff reviewed the supplemental reload licensing report for Unit 1 Cycle 14. The cycle-specific ASME overpressure analysis resulted in a peak vessel pressure of 1343 psig, which corresponds to a dome pressure of 1312 psig. The cycle-specific peak vessel pressure remains below the ASME limit of 1375 psig and the dome pressure remains below the TS 1325 psig safety limit. However, the cycle-specific ASME overpressure analysis was based on one SRV OOS, while the EPU ASME overpressure analysis was based on two SRVs OOS. In an RAI response, the licensee stated that with two SRVs OOS, the TS dome pressure limit of 1325 psig would be exceeded; therefore, Unit 1 will not operate with two SRVs OOS.

Based on the information submitted and the analyses performed, which demonstrate that for the actual core design, the dome pressure will be within the applicable limits, the NRC staff concludes that the BSEP Units 1 and 2 overpressure response is acceptable.

3.3 Reactor Pressure Vessel and Internals

3.3.1 Reactor Vessel Fracture Toughness

The licensee performed comprehensive reviews to assess the effects of increased power conditions on the reactor vessel and its internals. Reactor pressure vessel (RPV) embrittlement is caused by neutron exposure of the wall adjacent to the core (the "beltline" region). Operation at the EPU conditions results in a higher neutron flux, which increases the integrated fluence over the period of plant life. The licensee's reviews and associated analyses indicated that compliance with the original design and licensing criteria for the reactor vessel and internals is maintained during operation at the uprated power level.

The licensee used the GENE LTR, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2), Section 5.5.1.5 to describe the RPV fracture toughness evaluation process. This report was approved by the NRC staff.

The licensee recalculated the neutron fluence using the procedures included in the proprietary GE topical report NEDC-32984P, "GE Methodology to RPV Fast Neutron Flux Evaluations." This report was approved by the NRC staff. The end-of-life fluence was calculated using flux for EPU conditions and from the currently licensed fluence for pre-EPU conditions to evaluate the vessel against the requirements of 10 CFR 50, Appendix G. The results of these evaluations indicate that:

(a) The upper shelf energy (USE) remains bounded by the BWROG equivalent margin analysis, thereby demonstrating compliance with the USE requirements in 10 CFR Part 50, Appendix G.

(b) The beltline material reference temperature of the nil-ductility transition (RT_{NDT}) remains well within the 200^{0}F screening criterion as defined in Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials."

(c) The 32 effective full-power year (EFPY) shift is slightly increased, and consequently, requires a change in the adjusted reference temperature, which is the initial RT_{NDT} plus the shift plus a margin term. These values are provided in Tables 3-1 and 3-2 of the submittal for BSEP 1 and 2, respectively.

(d) The pressure-temperature (P-T) curves provided in the TS are being modified to accommodate the increase in shifts affecting the beltline portion of the curves. A separate submittal to the NRC concerning the P-T curve changes will be provided in a separate licensing amendment from the EPU.

(e) The reactor vessel material surveillance program includes three capsules. One capsule containing Charpy specimens was removed from each vessel after 8.67 EFPY (BSEP 1) and 10.9 EFPY (BSEP 2) of operation and tested. The remaining two capsules for each unit have been in the reactor vessel since plant startup and will remain in the vessel for future removal from the vessel.

The maximum operating dome pressure for EPU RTP is unchanged from that for current power operation. Therefore, no change in the hydrostatic and leakage test pressures is required. The vessel is still in compliance with the regulatory requirements during EPU conditions.
The NRC staff reviewed the licensee's evaluation regarding the effect of the power uprate on RPV fracture toughness. Based on this evaluation, the NRC staff concludes that EPU at the Brunswick plant will have a minor effect on the RPV and that the RPV will be in full compliance with the regulatory requirements during EPU conditions.

3.3.2 Reactor Vessel Integrity

The review of the safety analysis provided by the licensee focused on the effects of power uprate on the structural and pressure boundary integrity of the piping systems and components, their supports, reactor vessel and internal components, CRDM, certain safety-related pumps and valves, and BOP piping systems.

The GE generic guidelines for BWR power uprate were based on a 24% higher steam flow, an operating temperature increase to 556°F, and an operating pressure increase to 1095 psia. For BSEP, the maximum reactor vessel dome pressure is unchanged (remains at 1045 psia) from the CRTP level, and the dome temperature is also unchanged (remains at 549.9°F). The steam flow rate will increase from 11.089 $x10^6$ lb_m/hr to 12.781 $x10^6$ lb_m/hr (increase of approximately 15.3%). The maximum core flow rate remains unchanged for the proposed power uprate conditions at BSEP.

The stresses and CUFs for the reactor vessel components were evaluated by the licensee in accordance with the ASME *Boiler and Pressure Vessel Code*, Section III, 1965 Edition with addenda to and including Summer 1967, which is the Code of record at BSEP.

The licensee provided the calculated maximum stresses and CUFs for the most limiting reactor vessel components in Table 3-3 of GE LTR, NEDC-33039P. The licensee indicated that the current CUF values in Table 3-3 are the actual CUFs available at BSEP from the plant fatigue monitoring program based on the 27 and 28 years of operation life for Units 1 and 2, respectively. The CUFs for the 40 years are calculated based on the combination of the current CUFs and the CUFs for the remaining 13 (or 12) years of operation based on CUFs reported in the existing design basis stress report with consideration of increased temperature and flow in feedwater nozzles. The NRC staff finds the predicted CUFs for the remaining 13 (or 12) years of operation to be very conservative in comparison with the actual monitored CUFs and, therefore, acceptable. The reactor vessel components that are not listed in Table 3-3 have maximum stresses and CUFs that are either not affected by the power uprate or already bounded by those listed in the table. The maximum calculated stresses in Table 3-3 are within the allowable limits, and the CUFs are less than the code limit of unity. These calculated stresses are less than the allowable Code limits, and the NRC staff finds this acceptable.

3.3.3 Reactor Internal Pressure Differences

The information provided in section 3.3.3 of NEDC 33039P is evaluated in section 3.3.4 of this SE.

3.3.4 Reactor Internals Structural Evaluation

The licensee evaluated the effects of the BSEP Units 1 and 2 power uprate on the reactor vessel and internal components in accordance with its current design basis. The loads considered in the evaluation include reactor internal pressure difference (RIPD), LOCA, flow, acoustic, thermal, seismic, and dead weight. The licensee indicated that the load combinations for normal, upset and faulted conditions were considered consistent with the current design basis analysis. In its evaluation, the licensee compared the proposed power uprate conditions (pressure, temperature and flow) against those used in the design basis. For cases where the power uprate conditions are bounded by the design basis analyses, no further evaluation is performed. If the power uprate conditions are not bounded by the design basis, new stresses are determined by scaling up the existing design basis stresses proportionate to the proposed power uprate conditions. The resulting stresses are compared against the applicable allowable values, in accordance with the design basis. The NRC staff finds the methodology used by the licensee consistent with the NRC-approved methodology in Appendix I of GE Nuclear Energy NEDC-32424P-A, and is therefore acceptable.

The Code of record at BSEP is the ASME *Boiler and Pressure Vessel Code*, Section III, 1965 Edition with addenda to and including Summer 1967. The licensee indicated that for BSEP Units 1 and 2, the reactor internal components are not ASME Code components. However, ASME Code requirements have been used as guidelines in the design basis documents. The licensee also indicated that the evaluations supporting the thermal power increase were performed consistent with the design basis. The NRC staff finds this acceptable.

In its assessment of the potential for flow-induced vibration on the components, the licensee indicated that the steam separators and dryers in the upper zone of the reactor are mostly affected by the increased steam flow due to the proposed power uprate. The effects of the power uprate on the flow-induced vibration for other components in the reactor annulus and core regions are less significant, because the proposed power uprate conditions do not require any increase in core flow, and very little increase in the drive flow. For components other than the steam separators and dryers, the evaluation of flow-induced vibration for the reactor internal components was performed based on the vibration data recorded during startup testing at the GE prototype BWR/4 plant and at BSEP Unit 1. The vibration levels were calculated by extrapolating the recorded vibration data to power uprate conditions and compared to the plant allowable limits. The stresses at critical locations were calculated based on the extrapolated vibration peak response displacements and found to be within the GE allowable design criteria of 10 ksi. Stress values less than 10 ksi for stainless steel are within the endurance limit under which sustained operation is allowed without incurring any cumulative fatigue usage. The licensee concluded that vibration levels of all safety-related reactor internal components are within the acceptance criteria. The NRC staff finds the licensee’s specified stress limit of 10 ksi for the reactor internal components is reasonably conservative in comparison to the ASME Code limit of 13.6 ksi for the peak vibration stress and, therefore, acceptable.

The licensee indicated, in its letter dated January 24, 2002, that the steam dryers and separators are not safety-related components; however, their failure may lead to an operational concern. The licensee also indicated that, although the design basis criteria do not require evaluation of the flow-induced vibration or determination of cumulative fatigue usage for the steam separators and dryers, the maximum vibration level for the shroud head and steam separators is small in comparison to the allowable limit. The licensee also indicated that the dynamic pressure loads, which may induce vibration for the dryers during operation, are less than the pressure loads from the design basis faulted condition. In addition, the dryers will be visually inspected during removal in each refueling outage, and any significant cracking can be detected and repaired. The design basis for the steam dryers specifies that the dryers maintain

their structural integrity when subjected to a steamline break occurring beyond the MSIVs. Since the dome pressure is not changed, the current steam dryer analysis remains bounding for the proposed power uprate conditions.
On the basis of information provided by the licensee in its January 24, 2002, letter, the NRC staff finds that the licensee has reasonably demonstrated that the steam dryers and separators will meet their design basis requirements and maintain their structural integrity following the proposed EPU.

3.3.5 Flow-Induced Vibration

This evaluation is included in Section 3.5.

3.3.6 Steam Separator and Dryer Performance

The structural integrity evaluation for this system is included Section 3.3.4 above. The change in overall system performance is not a safety issue and does not require evaluation by the NRC staff.

3.4 Reactor Recirculation System

The primary function of the recirculation system is to vary the core flow and power during normal operation. However, the recirculation system also forms part of the reactor coolant system (RCS) pressure boundary.

The EPU operation is accomplished along an extension of the current MELLLA rod line with no increase in the maximum core flow. There is also no increase in the dome pressure during normal operation. However, the flatter EPU core design, with the higher average bundle power, would increase the two-phase core flow resistance, and will require an increase in the recirculation system drive flow. The licensee evaluated the recirculation system performance at the EPU RTP and determined that adequate core flow can be maintained for BSEP Unit 1. For BSEP Unit 2, the licensee stated that the core internal design and restrictive orificing limit the unit's ability to achieve full ICF of 104.5 percent without modifications. The licensee added that the core reload analyses are performed with the most conservative allowable core flow and that the EPU operation will be evaluated at a core flow of 104.5 percent.

The licensee also estimated that the required pump head and pump flow at the EPU RTP conditions indicate that the power demand for the recirculation motors would increase. For Unit 1, the licensee determined that the EPU RTP is within the capability of the recirculation system, but for Unit 2 the actual core flow will be limited to less than 104.5 percent unless modifications to the recirculation system are made.

In an RAI response, the licensee reported that EPU design calculations, assuming clean as-built conditions, indicate that at full EPU conditions, the recirculation pumps will deliver 1.8% less flow. The licensee stated that this corresponds to an expected maximum ICF of 102.3 percent for Unit 2, while Unit 1 can achieve 104.5 percent. The licensee added that the decrease in the maximum core flow for Unit 2 has no safety consequence, but it would have an economic consequence by reducing the effectiveness of the fuel utilization.

The NRC staff's audit included a review of the performance of the recirculation system. Since the 1.8 percent decrease in flow cited by the licensee is based on clean, as-built conditions of the recirculation system and core components, the evaluation does not account for the effects of additional core losses due to aging or crud built up in the jet pumps. In addition, the actual EPU core design, with more high powered bundles, would be expected to increase the core flow resistance. Therefore, the decrease in core flow at EPU RTP may be higher than the licensee expects for both units. This could potentially limit further the operating window at the EPU RTP. However, the safety analyses that demonstrate the units can meet the applicable fuel and system design limit are based on operation up to the ICF condition of 104.5%. Since the analyzed and licensed operating domain bound the achievable ICF statepoint, the limitations of the recirculation system is not a safety issue, as long as CP&L operates BSEP Units 1 and 2 within the licensed MELLLA boundary. Based on the discussion above, the NRC staff accepts the recirculation system performance at the EPU RTP.

The licensee evaluated the net positive suction head (NPSH) and found that EPU RTP conditions would not significantly increase the NPSH required or reduce the NPSH margin for the recirculation pumps. The cavitation of the recirculation pumps is a concern at lower power when there is not adequate feedwater flow to provide sufficient subcooling. The licensee will maintain the cavitation protection interlock in terms of absolute feedwater flow, corresponding to the MWt shown in the power/flow map. The NRC staff agrees with the licensee's assessment since it is consistent with the evaluation in Section F.4.2.6 of ELTR1.

During SLO, the thermal power is limited to $\leq$ 83.8% of the current rated power. Since the BSEP units currently operate along the MELLLA upper boundary rod line up to the CRTP, the absolute thermal power limit for SLO does not change. The licensee will maintain the same absolute thermal power, but the percentage of rated power would be decreased by the ratio of power increase (1.05/1.20).

Therefore, based on the information submitted, the responses to the RAIs, and the on-site review, the NRC staff concludes that the impacts on the recirculation system safety functions discussed in Supplement 1 to ELTR2 were adequately considered for the BSEP Units 1 and 2 and are acceptable.

3.5 Reactor Coolant Pressure Boundary Piping

The licensee evaluated the effects of the power uprate condition, including higher flow rate, temperature, pressure, fluid transients and vibration effects on the RCPB and BOP piping systems and components. The components evaluated included equipment nozzles, anchors, guides, penetrations, pumps and valves to pipe welds, flange connections, and pipe supports (including snubbers, hangers, and struts). The licensee indicated that the original Codes of record, as referenced in the original and existing design basis analyses, and analytical techniques were used in the evaluation. The NRC staff finds this acceptable.

The RCPB piping systems evaluated include the reactor recirculation, main steam, main steam drains, reactor core isolation cooling (RCIC), high-pressure coolant injection (HPCI), feedwater, reactor water cleanup (RWCU), core spray (CS), standby liquid control (SLC), residual heat removal (RHR), RPV head vent line, CRD piping and SRV discharge line systems. The evaluation used the United States of America Standards (USAS) B31.1, "Power Piping," 1967 Edition and 1973 Edition, which is the BSEP Code of record. The licensee indicated that the evaluation follows the process and methodology defined in Appendix K of ELTR1 and in Section 4.8 of Supplement 1 of ELTR2. In general, the licensee compared the increase in pressure, temperature and flow rate due to the power uprate against the same parameters used as input to the original design-basis analyses. The comparison resulted in the bounding percentage increases in stress for affected limiting piping systems. The bounding percentage increases are compared to the design margin between calculated stresses and the Code-allowable limits. The bounding percentage increases were also applied to the original calculated stresses for the piping to determine the stresses at the proposed power uprate condition. The NRC staff finds the methodology to be acceptable considering the conservatism in the application of the scaling factors for the power uprate stress to loading combinations that include individual loads (i.e., dead weight and seismic) that are not affected by the power uprate.

In its January 24, 2002, response to the NRC staff's RAI, the licensee provided maximum calculated stresses for the limiting feedwater piping at BSEP Units 1 and 2 for the proposed power uprate. The maximum stresses are less than the Code-allowable limits. On the basis of its evaluation, the licensee concluded that for all RCPB piping systems, the original piping design has sufficient design margin to accommodate the changes due to the proposed power uprate. The NRC staff reviewed relevant portions of the evaluation provided by the licensee in its January 24, 2002, letter, and finds the licensee's conclusion acceptable.

The licensee's evaluations of the stresses for BOP piping and related components, connections, and supports are similar to the evaluation of the RCPB piping and supports. The licensee indicated that the original Code of record as referenced in the pertinent calculations, Code-allowables, and analytical techniques were used and that no new assumptions were introduced. The BOP systems evaluated by the licensee include piping that is affected by the power uprate but not evaluated in Section 3.5 of GE NEDC-33039P-A, such as feedwater condensate and heater drain, main steam drain lines, turbine bypass line, and portions of the main steam, feedwater, CS, RCIC, HPCI, and RHR systems outside the primary containment. The existing design analyses of the affected BOP piping systems were reviewed against the uprated power conditions. As a result of its evaluation, the licensee indicated that all piping meets the requirements of USAS B31.1-1967, which is the Code of record. There are sufficient margins in the original design analyses to accommodate the changes due to the proposed power uprate. The NRC staff finds that the stresses provided in the licensee's January 24, 2002, response for the most limiting feedwater and CS piping outside the containment at the power uprate condition are within the Code-allowable limits and are, therefore, acceptable.

3.5.1 Recirculation System Evaluation

This evaluation is included in Section 3.5.

3.5.1.1 Recirculation System Erosion/Corrosion

The licensee stated that the recirculation system components are made of stainless steel, and system flow increase due to the EPU is minor and, therefore, erosion/corrosion is not a concern for this system. The NRC staff reviewed the licensee evaluation and reasoning and finds the licensee's conclusion acceptable.

3.5.2 Main Steam and Associated Piping System Evaluation

This evaluation is included in Section 3.5.

3.5.2.1 Main Steam and Associated Piping System Erosion/Corrosion

Flow-accelerated corrosion (FAC) occurs in the systems containing components made from carbon steel and exposed to flowing water. It results in a loss of material from the affected components. In the Brunswick plant, the following systems were identified to contain components susceptible to FAC: main steam and associated piping, feedwater, RPV vent, bottom head drain, and portions of the HPCI, RCIC, and RWCU systems. FAC also affects the systems containing carbon steel components in the BOP.

The amount of damage caused by FAC is a function of fluid velocity, temperature, and moisture content. Since these parameters may undergo a change after the EPU, the licensee evaluated the effect of this change on FAC.

Currently, the licensee has the FAC program, which was implemented and is maintained in accordance with NRC Generic Letter (GL) 89-08 and the recommendations of the Electric Power Research Institute (EPRI) specified in the NSAC/202L report. The program consists of predicting the loss of material caused by FAC using the EPRI-developed CHECWORKS computer code and performing inspections of the components that are predicted to be susceptible to FAC. The inspections involve ultrasonic measurements of the wall thickness. Typically, 75 components are inspected each refueling outage to confirm the predicted corrosion rates.

The licensee’s experience concerning the effect of the EPU on FAC is largely based on the corrosion rates measured during the 5-year period since the previous 5-percent power uprate was implemented at BSEP. The experience has indicated that, in general, power uprate has only a relatively minor effect on FAC. This finding was confirmed by the results of the licensee’s evaluations of the proposed 20-percent EPU. Notwithstanding this finding, the licensee will upgrade its FAC program following the EPU before using it for controlling FAC in the plant operating at a higher power level. The upgrading of the FAC program will include changes to the input parameters in the CHECWORKS code and modification of the component inspection procedures based on the results predicted by the code. As a result, component inspection frequency and the repair or replacement of the components approach limiting wall thickness will be readjusted.

The NRC staff reviewed the licensee’s evaluation regarding the effect of the power uprate on FAC. Based on this evaluation, the NRC staff concludes that, following the EPU in the Brunswick plant, only minor changes in wall thinning due to FAC are expected to occur and the licensee-proposed modification of the FAC program will ensure timely repair or replacement of components damaged by FAC.

3.5.3 Feedwater Evaluation

3.5.3.1 Feedwater Pipe Stress

This evaluation is included in Section 3.5.

3.5.3.2 Feedwater Pipe Supports

The licensee evaluated pipe supports such as snubbers, hangers, struts, anchors, equipment nozzles, guides, and penetrations by evaluating the piping interface loads due to the increases in pressure, temperature, and flow for affected limiting piping systems. In its January 24, 2002, response to the NRC staff's RAI, the licensee provided the limiting piping interface feedwater nozzle loads, which are shown to be within the allowable loads. The licensee also indicated that for the limiting BOP piping, support loads due to the proposed power uprate are within the allowable limits. In cases where the support loads are affected by the power uprate, the calculations for the support components were updated to determine the acceptability of the pipe supports. The NRC staff finds the licensee's evaluation acceptable.

3.5.3.3 Feedwater Erosion/Corrosion

FAC occurs in the systems containing components made from carbon steel and exposed to flowing water. It results in a loss of material from the affected components. In the Brunswick plant, the following systems were identified to contain components susceptible to FAC: main steam and associated piping, feedwater, RPV vent, bottom head drain, and portions of the HPCI, RCIC, and RWCU systems. FAC also affects the systems containing carbon steel components in the BOP.

The amount of damage caused by FAC is a function of fluid velocity, temperature, and moisture content. Since these parameters may undergo a change after the EPU, the licensee evaluated the effect of this change on FAC.

Currently, the licensee has the FAC program which was implemented and is maintained in accordance with NRC GL 89-08 and the recommendations of EPRI specified in the NSAC/202L report. The program consists of predicting the loss of material caused by FAC using the EPRI developed CHECWORKS computer code and performing inspections of the components that are predicted to be susceptible to FAC. The inspections involve ultrasonic measurements of the wall thickness. Typically, 75 components are inspected each refueling outage to confirm the predicted corrosion rates.

The licensee's experience concerning the effect of the EPU on FAC is largely based on the corrosion rates measured during the 5-year period since the previous 5-percent power uprate was implemented at BSEP. The experience has indicated that, in general, power uprate has only a relatively minor effect on FAC. This finding was confirmed by the results of the licensee's evaluations of the proposed total 20-percent EPU. Notwithstanding this finding, the licensee will upgrade its FAC program following the EPU before using it for controlling FAC in the plant operating at a higher power level. The upgrading of the FAC program will include changes to the input parameters in the CHECWORKS code and modification of the component inspection procedures based on the results predicted by the code. As a result, component inspection frequency and the repair or replacement of the components approach limiting wall thickness will be readjusted.

The NRC staff reviewed the licensee's evaluation regarding the effect of the power uprate on FAC. Based on this evaluation, the NRC staff concludes that, following the EPU in the Brunswick plant, only minor changes in the wall thinning due to FAC are expected to occur and the licensee-proposed modification of the FAC program will ensure timely repair or replacement of the components damaged by the FAC.

3.5.4 Other RCPB Piping Evaluation (Inside Containment)

This evaluation is included in Section 3.5.

3.5.4.1 Other RCPB Piping Evaluation Erosion/Corrosion

FAC occurs in the systems containing components made from carbon steel and exposed to flowing water. It results in a loss of material from the affected components. In the Brunswick plant, the following systems were identified to contain components susceptible to FAC: main steam and associated piping, feedwater, RPV vent, bottom head drain, and portions of the HPCI, RCIC, and RWCU systems. FAC also affects the systems containing carbon steel components in the BOP.

The amount of damage caused by FAC is a function of fluid velocity, temperature, and moisture content. Since these parameters may undergo a change after the EPU, the licensee evaluated the effect of this change on FAC.

Currently, the licensee has the FAC program which was implemented and is maintained in accordance with NRC GL 89-08 and the recommendations of EPRI specified in the NSAC/202L report. The program consists of predicting the loss of material caused by FAC using the EPRI developed CHECWORKS computer code and performing inspections of the components that are predicted to be susceptible to FAC. The inspections involve ultrasonic measurements of the wall thickness. Typically, 75 components are inspected each refueling outage to confirm the predicted corrosion rates.

The licensee’s experience concerning the effect of the EPU on FAC is largely based on the corrosion rates measured during the 5-year period since the previous 5-percent power uprate was implemented at BSEP. The experience has indicated that, in general, power uprate has only a relatively minor effect on FAC. This finding was confirmed by the results of the licensee’s evaluations of the proposed total 20-percent EPU. Notwithstanding this finding, the licensee will upgrade its FAC program following the EPU before using it for controlling FAC in the plant operating at a higher power level. The upgrading of the FAC program will include changes to the input parameters in the CHECWORKS code and modification of the component inspection procedures based on the results predicted by the code. As a result, component inspection frequency and the repair or replacement of the components approach limiting wall thickness will be readjusted.

The NRC staff reviewed the licensee’s evaluation regarding the effect of the power uprate on FAC. Based on this evaluation, the NRC staff concludes that, following the EPU in the Brunswick plant, only minor changes in the wall thinning due to FAC are expected to occur and the licensee- proposed modification of the FAC program will ensure timely repair or replacement of the components damaged by the FAC.

3.5.5 Piping Flow-Induced Vibration

The licensee evaluated the flow-induced vibration (FIV) levels of the safety-related main steam and feedwater piping systems that are projected to increase in proportion to the increase in the fluid density and the square of the fluid velocity following the proposed power uprate. To ensure that the vibration level will be below the acceptable limit (material endurance limit of 7,690 psi for carbon steel piping), the licensee is committed to perform a piping vibration startup test program, as outlined in Section 10.4.3 of the amendment submittal. The startup testing would include monitoring and evaluating the FIV during the plant startup for the proposed uprated power operation. Vibration data will be collected at test conditions, which correspond to 50, 75, and 100 percent of the ORTP, and to each 5-percent step increase in power level above 100 percent of ORTP, up to the final proposed uprated power level. The measured vibration levels are compared against the acceptance criteria where the allowable vibration stress levels are set by the design fatigue endurance stress intensity limits established by the licensee for stainless and carbon steel. The NRC staff finds the licensee's methodology in assessing the FIV acceptable and consistent with the ASME Section III Code and the ASME OM-3, "Requirements for Preoperational and Initial Startup Vibration Testing of Nuclear Power Piping Systems."

3.6 Main Steam Flow Restrictors

The licensee stated that there is no impact on the structural integrity of the restrictors as a result of the proposed power uprate. In Section 3.2 of the power uprate license amendment request, the licensee indicated that a higher peak RPV dome pressure of 1306 psig results from the proposed BSEP plant power uprate conditions, but this value remains below the ASME Code limit of 1375 psig (110% of design pressure). Also, the restrictors were designed for a maximum differential pressure due to the choke flow condition, which is bounding for the uprated power condition. Therefore, the main steamline flow restrictors will maintain their structural integrity following the power uprate. The NRC staff finds this acceptable.

3.7 Main Steam Isolation Valves

The MSIVs are part of the RCPB and perform the safety function of steamline isolation during abnormal operation. The MSIVs must be able to close within the specified time limits at all design and operating conditions upon receipt of a closure signal. They are designed to satisfy leakage limits set forth in the TS. The licensee indicated that the MSIVs have been generically evaluated, as discussed in Section 4.7 of ELTR2. The licensee stated that the conditions for BSEP 1 and 2 are bounded by those in the generic analysis. Although the dome pressure does not increase with the EPU, the increase in flow rate assists MSIV closure. The TS closure timing requirements of $\geq$3 and $\leq$5 seconds will continue to be met as discussed in response to RAI 17-1. Therefore, operation at the EPU as indicated above remains bounded by the conclusion of the generic evaluation in Section 4.7 of ELTR2, and the MSIVs are acceptable for EPU operation.

Based on the review of the licensee's rationale and evaluation, the NRC staff finds that plant operation at the proposed EPU level will not affect the ability of the MSIVs to perform their isolation safety function.

3.8 Reactor Core Isolation Cooling System

The RCIC system provides core cooling in the event of a transient where the RPV is isolated from the main condenser concurrent with the loss-of-feedwater (LOFW) and the RPV pressure is greater than the maximum allowable for the initiation of a low-pressure core cooling system. The RCIC system is evaluated on its ability to provide core cooling and maintain the water level above the top of the active fuel (TAF).

Section 5.6.7 of ELTR1 provides the scope of the RCIC system evaluation. The licensee evaluated the RCIC high-pressure injection capability, stating that the maximum injection pressure for RCIC is based on the upper analytical setpoint for the lowest available group of SRVs operating in the spring safety mode. For the EPU operation, the BSEP Units 1 and 2 SRV actuation setpoints and the operating reactor dome pressure do not change. Since there are no changes to the RCIC high-pressure injection parameters for the EPU conditions, the licensee determined that the RCIC system capability to inject the design flow rate of 400 gpm would remain the same during the design-basis transients.

Section 3 of ELTR2 provided an evaluation of the RCIC design basis. The report stated that for BWR 4, 5, and 6 plants, the RCIC system (the smaller of the two high-pressure supply systems) should maintain the reactor water level so that the very low level trip setpoint (Level 1) for the low-pressure ECCS would not trip and the MSIVs should not close. ELTR 2 classified the Level 1 setpoint margin as an operational criteria. Due to the reference leg heating effect during a LOCA, the licensee raised the nominal low water level (Level 1 in ELTR2 is designated as LL3/L1 for BSEP) setpoint for both units to compensate for the instrument level inaccuracies during a LOCA. As a result, the BSEP units do not currently meet the LL3/L1 setpoint margin and the licensee stated that the BSEP units would not be able achieve the setpoint margin. Due to the higher stored and decay energy for the EPU conditions, the minimum sensed water level inside and outside the shroud for LOFW transient will decrease. The level would drop to LL3/L1, initiating the automatic depressurization system (ADS) timer and MSIV closure. The licensee stated that the operators will inhibit ADS actuation to prevent depressurization following an LOFW transient with isolation, thus allowing the RCIC system to perform its design basis function.

The RCIC system is evaluated on its ability to provide core cooling and maintain the water level above the TAF. The licensee performed the LOFW transient to evaluate the system’s capability to maintain the water level above the TAF and determined that the RCIC system is capable of maintaining water level above the TAF. Since, under EPU conditions, the BSEP units might not be able to avoid the water level outside the shroud reaching the LL3/L1 level (ADS timer initiated and MSIVs actuated), the NRC staff confirmed that the RCIC system performance was evaluated based on a loss of all feedwater, with the reactor isolated.

Section 4.2.3 of Supplement 1 to ELTR2 discussed the potential for turbine overspeed of the steam-driven RCIC and HPCI turbine pumps. The supplement stated that startup transients for the HPCI and the RCIC systems at a potentially higher steam inlet pressure may result in an increased initial turbine acceleration rate, increasing the peak initial speed and the probability of the system tripping. The RCIC startup transients are dependent on the reactor pressure, and the Supplement recommended that the modifications described in GE Services Information Letter #377, “RCIC Startup Transient Improvement with Steam Bypass,” be implemented to assure RCIC availability for power uprates that involve reactor pressure increases. CP&L did not implement the RCIC turbine startup control function modifications recommended in GE Services Information Letter #377. The licensee evaluated the potential impact of the EPU operation on the RCIC turbine startup transient and determined that the power uprate will not result in changes to the startup transient or the system reliability.

The RCIC performance evaluation depends on the RCIC system's capability to inject the required flow rate for the range of EPU reactor pressures during isolation transients, without overspeeding of the turbine. For EPU operation, the stored energy and decay heat would be higher, while the SRV capacity remains the same. Therefore, the startup transient for the RCIC turbine would depend on the SRV lift setpoint, the capability of the SRVs to handle the higher steam flow during isolation transient, and the corresponding reactor pressure at the time the RCIC pump startup to inject. For the LOFW event, the operators would inhibit the ADS as long as the level is steady or rising, delaying reactor depressurization. In an RAI response, the licensee confirmed that actuation of the lowest group of SRVs could maintain the reactor pressure during a LOFW transient at the TS limit of 1163.9 psig (1130 psig + 3 %). Based on data from 14 RCIC startups, the licensee determined that the initial speed peak for the RCIC turbine increases by 2.45 rpm/psig as the steam dome pressure increases. With an initial RCIC turbine speed peak of 4600 rpm for nominal reactor pressure of 960 psig, the licensee predicted that the turbine speed peak for reactor pressure of 1164 psig would be 5100 rpm. The overspeed trip allowable range is 5513 to 5737 rpm. Therefore, there is an adequate margin to preclude an inadvertent overspeed trip of the RCIC turbine. Based on the licensee's evaluation of the turbine speed during the RCIC injection, and the reported dome pressure during the isolation transient, the NRC staff concludes that the RCIC system can inject in the event of an LOFW transient with isolation, without RCIC turbine overspeed trip.

The design-basis maximum reactor pressure for the rated flow for the RCIC system is 1183 psig. Since the licensee determined that for LOFW with isolation transient, the reactor dome pressure would be maintained at or below 1164 psig, the NRC staff accepts the licensee's assessment that the RCIC would be able to provide the design flowrate.

The licensee evaluated the NPSH requirements for the RCIC pumps and determined that the EPU operation does not decrease the NPSH available for the RCIC pump, nor does it increase the NPSH required above the system design value.

Based on the information submitted and obtained during the NRC staff's audit and the responses to the RAIs, the NRC staff concludes that the licensee has evaluated the capability of the RCIC system to perform its function for the EPU operation consistent with the guidelines in ELTR1 and ELTR2. The NRC staff finds that the licensee's evaluations of the RCIC system performance is acceptable.

3.9 Residual Heat Removal System

The RHR system, which is designed to maintain the coolant inventory in the reactor vessel and to remove heat from the primary system and containment following reactor shutdown for both normal and post-accident conditions, would operate in the following modes: shutdown cooling mode; suppression pool cooling mode; containment spray cooling mode and fuel pool cooling assist mode. The following evaluates the impact of the EPU on various RHR operating modes.

3.9.1 Shutdown Cooling Mode

The objective of normal shutdown is to reduce the bulk reactor temperature after scram to 125°F in approximately 20 hours using two shutdown cooling (SDC) heat exchanger loops. RG 1.139, "Guidance for Residual Heat Removal," provides an alternative approach to demonstrate SDC capability: the RHR system can reduce the reactor coolant temperature to 200°F within 36 hours.

The decay heat increases proportionally to the operating reactor power level; therefore, for the EPU operation, the time required to reduce the reactor temperature to the shutdown conditions increases. The PUSAR stated that the increase in the cooldown time has no effect on the plant safety and did not provide additional information. Consequently, during the audit, the NRC staff reviewed the SDC capability for the BSEP units for the EPU operation. In an RAI response, the licensee stated that BSEP Units 1 and 2 would reach a reactor coolant temperature of 125°F after 36 hours with two SDC loops in service, which exceeds the 20-hour guidance. The licensee added that the original 20-hour time was [ ]to ensure that SDC does not become limiting during normal reactor shutdown. [ ]. For EPU operation, it would take longer to cool the reactor to 125°F during normal reactor shutdown. The licensee concluded that the longer SDC time was acceptable for EPU operation because it will not affect the units' safety, although it will impact operational activities such as plant availability and refueling.

Since a number of TS limiting conditions for operation (LCOs) require the plant to be brought to cold shutdown conditions (Mode 4) within a specified time, the NRC staff evaluated the units' ability to achieve the cold shutdown condition in 36 hours. For BSEP Units 1 and 2, the cold shutdown condition in Mode 4 is defined as a reactor temperature less or equal to 212°F. In an RAI response, the licensee stated that BSEP Units 1 and 2 can achieve hot shutdown (Mode 4) in approximately 10 hours, with a single SDC loop in operation. This is consistent with the alternative SDC option discussed in RG 1.139. Therefore, based on the NRC staff's audit, the RAI response, and the units' ability to reach Mode 4 within the TS-required time, the NRC staff finds the SDC capability at the EPU condition acceptable.

3.9.2 Suppression Pool Cooling Mode

The Suppression Pool Cooling (SPC) mode of the RHR system is designed to remove heat discharged into the suppression pool to maintain pool temperature below the TS limit during normal plant operation and below the suppression pool design temperature limit after an accident. The power uprate increases the reactor decay heat, which increases the heat input to the suppression pool during a LOCA, which results in a higher peak suppression pool temperature. The EPU effect on suppression pool temperature and cooling after a design-basis LOCA is addressed in Section 4.1.1. The effect of higher temperature on available NPSH is addressed in Section 4.2.5.

3.9.3 Containment Spray Cooling Mode

The Containment Spray Cooling (CSC) mode is designed to spray water from the suppression pool via spray headers in the drywell and suppression chambers to reduce containment pressure and temperature during post-accident conditions. The power uprate increases the containment spray water by a few degrees. This increase has a negligible effect on the use of the CSC mode to maintain the containment pressure and temperature within their design limits as the peak pressure and temperatures are reached well before the use of containment spray is assumed to occur.

Based on the review of the licensee's rationale and evaluation, we concur that plant operations at the proposed EPU level will have an insignificant impact on the CSC mode.

3.9.4 Steam Condensing Mode

This is not a safety-related mode, and has been disabled. No evaluation is required.

3.9.5 Fuel Pool Cooling Assist Mode

Cross-tie piping is provided between the spent fuel pool (SFP) cooling and cleanup (SFPCC) system and the RHR system. In the event that the SFP heat load exceeds the heat removal capability of the SFPCC system, the RHR system can be operated in conjunction with the SFPCC system by means of the cross-tie to maintain the SFP below the SFP temperature limit of 150^0F. Evaluation of RHR system operation in this mode is discussed in Section 6.3.1.

3.10 Reactor Water Cleanup System

The RWCU system removes soluble and particulate impurities from the reactor water, reducing their accumulation in the RCS. Maintaining low concentrations of impurities prevents corrosion of reactor components and buildup of high radiation levels. Since the RWCU system mass flow rate does not change after the power uprate, increasing feedwater flow will reduce the fraction of feedwater that is processed by the RWCU. This will result in increasing reactor water conductivity. However, the conductivity never will exceed the limits recommended by EPRI for the BWR coolant. Higher feedwater flow will also cause an increase of the concentration of insoluble iron. The increased contaminant removal rate that is required to maintain water chemistry quality in the reactor will result in a higher depletion rate of resins. This will require more frequent backwashes of the RWCU filter demineralizers.

The licensee reviewed the RWCU piping and components for operation after the power uprate. The licensee found that the system will meet all its safety and design objectives. The RWCU system will also have provisions for appropriate isolation in the case of a high energy pipe break in the system.

The NRC staff reviewed and evaluated the licensee's analyses of the RWCU performance and concludes that it will not be affected by the power uprate.

3.11 Balance-of-Plant Piping Evaluation

3.11.1 BOP Pipe Stresses

This evaluation is included in Section 3.5.

3.11.2 BOP Pipe Supports

This evaluation is included in Section 3.5.

3.11.3 BOP Erosion/Corrosion

FAC occurs in the systems containing components made from carbon steel and exposed to flowing water. It results in a loss of material from the affected components. In the Brunswick plant, the following systems were identified to contain components susceptible to FAC: main steam and associated piping, feedwater, RPV vent, bottom head drain, and portions of the HPCI, RCIC, and RWCU systems. FAC also affects the systems containing carbon steel components in the BOP.

The amount of damage caused by FAC is a function of fluid velocity, temperature, and moisture content. Since these parameters may undergo a change after the EPU, the licensee evaluated the effect of this change on FAC.

Currently, the licensee has the FAC program which was implemented and is maintained in accordance with NRC GL 89-08 and the recommendations of EPRI specified in the NSAC/202L report. The program consists of predicting the loss of material caused by FAC using the EPRI developed CHECWORKS computer code and performing inspections of the components that are predicted to be susceptible to FAC. The inspections involve ultrasonic measurements of the wall thickness. Typically, 75 components are inspected each refueling outage to confirm the predicted corrosion rates.

The licensee's experience concerning the effect of the EPU on FAC is largely based on the corrosion rates measured during the 5-year period since the previous 5-percent power uprate was implemented at BSEP. The experience has indicated that, in general, power uprate has only a relatively minor effect on FAC. This finding was confirmed by the results of the licensee's evaluations of the proposed total 20-percent EPU. Notwithstanding this finding, the licensee will upgrade its FAC program following the EPU before using it for controlling FAC in the plant operating at a higher power level. The upgrading of the FAC program will include changes to the input parameters in the CHECWORKS code and modification of the component inspection procedures based on the results predicted by the code. As a result, component inspection frequency and the repair or replacement of the components approach limiting wall thickness will be readjusted.

The NRC staff reviewed the licensee's evaluation regarding the effect of the power uprate on FAC. Based on this evaluation, the NRC staff concludes that, following the EPU in the Brunswick plant, only minor changes in the wall thinning due to FAC are expected to occur and the licensee- proposed modification of the FAC program will ensure timely repair or replacement of the components damaged by the FAC.

4.0 ENGINEERING SAFETY FEATURES

4.1 Containment System Performance

The BSEP UFSAR provides the results of analyses of the containment response to various postulated accidents that constitute the design basis for the containment. Operation with 15% power uprate from 2558 MWt to 2923 MWt would change some of the conditions and assumptions of the containment analyses. Topical Report NEDC-32424, "Generic Guidelines For General Electric Boiling Water Reactor Extended Power Uprate," Section 5.10.2 requires the power uprate applicant to show the acceptability of the effect of the uprate power on containment capability. These evaluations include containment pressures and temperatures, LOCA containment dynamic loads, SRV containment dynamic loads, and subcompartment pressurization. Appendix G of NEDC-32424 prescribes the generic approach for this evaluation and outlines the methods and scope of plant-specific containment analyses to be done in support of power uprate. Appendix G states that the applicant will analyze short-term containment pressure and temperature response using the previously applied GE code, M3CPT. The BSEP EPU analyses uses the LAMB code with Moody's Slip Critical Flow Model to generate the blowdown flowrates, which are then used as inputs to M3CPT. This approach, using a code with a more detailed RPV model, results in more realistic break flows for input to M3CPT, and differs from the current UFSAR analysis, which uses the Homogeneous Equilibrium Model.

Plant-specific use of the LAMB code, which has been previously reviewed by the NRC for Appendix K LOCA analyses, was addressed in ELTR-1, Appendix G.

Appendix G of NEDC-32424 also requires the applicant to perform long-term containment heat-up (suppression pool temperature) analyses for the limiting UFSAR events to show that pool temperatures will remain within limits for suppression pool design temperature, ECCS NPSH, and equipment qualification temperatures. These analyses can be performed using the GE computer code SHEX. SHEX is partially based on M3CPT and is used to analyze the period from when the break begins until after peak suppression pool heatup (i.e., the long-term response). The SHEX code was already used for the BSEP UFSAR analysis, and its use was preceded by performing confirmatory calculations for validating the results using the HXSIZ code. Therefore, the use of the SHEX code is within the current licensing basis and is acceptable for EPU containment analyses.

4.1.1 Containment Pressure and Temperature Response

Short-term and long-term containment analyses results following a large break inside the drywell are documented in the BSEP UFSAR. The short-term analysis was performed to determine the peak drywell and wetwell pressure response during the initial blowdown of the reactor vessel inventory into the containment following a large break inside the drywell (design-basis accident (DBA) LOCA). The long-term analysis was performed to determine the peak pool temperature response considering decay heat addition to the suppression pool. In its response to the NRC staff's RAI dated February 13, 2002, the licensee provided both short-term and long-term curves for parameters of interest for containment response for a DBA-LOCA including temperature and pressure for drywell and wetwell atmosphere, and suppression pool temperature.

The licensee indicated that the containment analyses were performed in accordance with NRC guidelines using GE codes and models. As noted above, the M3CPT code was used to model the short-term containment pressure and temperature response. The licensee also indicated that the SHEX code was used to model the long-term containment pressure and temperature response for EPU.

4.1.1.1 Long-Term Suppression Pool Temperature Response

(a) Bulk Pool Temperature

The licensee indicated that the long-term bulk suppression pool temperature response with the EPU was evaluated for the DBA LOCA. The bounding analysis was performed at 102% of EPU RTP. The analysis was performed using the SHEX code and the decay heat model ANS/ANSI 5.1-1979 with an uncertainty adder of two sigma. The EPU analyses used a more conservative service water temperature of 92°F and direct pool cooling from an RHR heat exchanger, whereas the UFSAR analysis used a service water temperature of 90°F and assumed operation of the containment sprays. We have determined that the ANS/ANSI 5.1-1979 decay heat model with an uncertainty adder of two sigma and more conservative service water temperature of 92°F and direct pool cooling are acceptable for calculating maximum pool temperature.

The peak bulk suppression pool temperature was calculated to be 207.7°F at EPU, based on revised EPU methodology, which is an increase of 18.3°F in peak pool temperature from 189.4°F over the current licensing basis. The EPU results in a 9.8°F increase in peak pool temperature over the current power level temperature, using EPU methodology and input assumptions. The calculated peak suppression pool temperature of 207.7°F at 102% of EPU power level remains below the wetwell structure design temperature of 220°F.

The effects of the EPU on NPSH for pumps taking suction from the suppression pool are discussed in Section 4.2.5.

Based on its review of the licensee's analyses, and experience gained from review of power uprate applications for other BWR plants, the NRC staff concludes that the peak bulk suppression pool temperature response remains acceptable for the power uprate.

(b) Local Pool Temperature with SRV Discharge

The local pool temperature limit for SRV discharge is specified in NUREG-0783, "Suppression Pool Temperature Limits for BWR Containment," because of concerns resulting from unstable condensation observed at high pool temperatures in plants without quenchers. Elimination of this limit for plants with quenchers on the SRV discharge lines is justified in GE report NEDO-30832, "Elimination of Limit on Local Suppression Pool Temperature for SRV Discharge with Quenchers." In a Safety Evaluation Report (SER) dated August 29,1994, the NRC staff eliminated the maximum local pool temperature limit for plants with quenchers, provided that steam entrainment in the ECCS suction is not a concern. Because BSEP has SRV quenchers, no evaluation of the local pool temperature limit is necessary to address the possibility of unstable condensation. However, it is necessary to ensure that steam ingestion in the ECCS suction line is not of concern during steam SRV discharge at high pool temperatures, since the top of suction strainer is located above the quencher.

The licensee indicated that an evaluation was performed to determine whether steam flow from the quencher would be entrained into the ECCS suction strainer. The behavior of the steam plume from the quencher, relative to entrainment flow path to the ECCS suction strainer, was analyzed at EPU conditions. The premise was that steam ingestion would be predicted if the quencher steam plume intersects any part of the ECCS suction strainer or the entrainment envelope of the suction strainer. In a letter dated October 17, 2001, the licensee indicated that the size of the steam plume generated from an SRV quencher was calculated to determine the boundary of the steam plume, with the conservative assumption that the suppression pool is saturated in the region around the SRV quenchers. Then, the envelope of flow drawn into the suction strainers was determined, based on the geometric size and orientation of the strainer, and the volumetric flow into the strainer. The entrainment envelope represents the flow boundary within which rising steam bubbles can be drawn into the strainer. The results of these calculations show that steam ingestion in the ECCS suction strainer is not predicted for BSEP. Therefore, based on the plants with quenchers on the SRV discharge line and results of this evaluation, the local pool temperature limit specified in NUREG-0783 can be eliminated.

The NRC staff reviewed the licensee's rationale and evaluation, and finds that plant operation at the EPU power level will have no adverse impact on the local pool temperature with SRV discharge, and therefore remains acceptable.

4.1.1.2 Short-Term Containment Airspace Temperature Response

The containment airspace temperature limit of 340°F was based on a bounding analysis of the superheated gas temperature that can be reached with blowdown of steam to the drywell during a DBA-LOCA. The licensee calculated the peak DBA-LOCA drywell gas temperature of 293°F at the EPU level, which remains below the drywell airspace design temperature of 340°F. The current licensing basis analysis had calculated a temperature of 286.7°F. Using the same methods as the EPU analyses, the peak drywell air temperature for the CRTP was calculated to be 290.4°F; 2.6°F lower than the calculated temperature at EPU power. The calculated EPU peak DBA-LOCA drywell air temperature of 293°F also remains below the shell design temperature of 300°F.

The licensee indicated that the limiting DBA with respect to peak drywell temperature is a steamline break. A steamline break produces a higher drywell temperature response than the DBA-LOCA (liquid line break) because the steam has a higher energy content than liquid at the same pressure. The licensee analyzed four break sizes ranging from 0.01 to 0.75 ft^2. The maximum peak airspace temperature for the four break sizes was calculated to be 338.1°F, which occurs prior to manual initiation of containment spray and remains below the airspace design temperature of 340°F. The calculated resultant peak shell temperature of 276.1°F also remains below the shell design temperature of 300°F. The peak values were obtained using the methods and assumptions consistent with the DBA-LOCA analysis for the EPU. Therefore, the drywell airspace temperature response remains acceptable for the EPU.

The licensee also indicated that the long-term wetwell airspace temperature essentially follows the suppression pool temperature, and its peak value of 207.7°F for the design-basis case remains below the wetwell design temperature of 220°F. Therefore, the wetwell airspace temperature response also remains acceptable at EPU.

Based on its review of the licensee's rationale and evaluation, the NRC staff finds that the drywell and wetwell air temperature response will remain acceptable after the EPU.

4.1.1.3 Short-Term Containment Pressure Response

The licensee indicated that the short-term containment response analyses were performed for the limiting DBA-LOCA, which assumes a double-ended guillotine break of a recirculation suction line (RSLB), to demonstrate that operation at the EPU level does not result in exceeding the containment design pressure limits. The short-term analysis covers the blowdown period during which the maximum drywell and wetwell pressures occur. These analyses were performed at 102% of EPU RTP per RG 1.49, with the M3CPT code except that the break flow is calculated using a more detailed RPV model (LAMB with Moody's Slip Critical Flow Model) than used for previous licensing basis analyses. The use of this model was addressed in NRC-approved topical report ELTR1. These analyses calculated a peak short-term drywell pressure of 46.4 psig and a peak short-term wetwell pressure of 31.1 psig at EPU, which remains below the drywell and wetwell design pressure of 62 psig.

At the CRTP level, these analyses calculated a peak drywell pressure of 44.2 psig (UFSAR value is 40.9 psig) and a wetwell pressure of 30.5 psig (22.0 psig secondary peak value based on the current methods for comparison with the UFSAR value of 14.0 psig). In a letter dated October 17, 2001, the licensee indicated that the primary reason for the change in secondary peak wetwell pressure is that the UFSAR assumed the operation of containment sprays, whereas direct pool cooling was assumed for the EPU evaluation. With containment sprays in operation, the drywell and wetwell airspace temperatures are considerably lower compared to direct pool cooling. Consequently, the wetwell pressure obtained with spray cooling for the UFSAR is lower than the value obtained with direct pool cooling for the EPU.

These results show that the calculated maximum drywell pressure of 46.4 psig and maximum wetwell pressure of 31.1 psig after the EPU remain bounded by the containment design pressure value of 62.0 psig.

Based on its review of the licensee's evaluation, the NRC staff agrees with the licensee's conclusion that the containment pressure response following a postulated LOCA will remain acceptable after the EPU.

4.1.2 Containment Dynamic Loads

4.1.2.1 LOCA Containment Dynamic Loads

The licensee indicated that the LOCA containment dynamic loads analysis for the EPU is based primarily on the short-term DBA-LOCA analyses. These analyses were performed as described in Section 4.1.1.3, using the Mark I Containment Long Term Program method, except that the break flow is calculated using the more detailed reactor pressure vessel model of NEDE-20566-P-A, GE model for LOCA Analyses in accordance with 10CFR 50 Appendix K. These analyses provide calculated values for the controlling parameters for the dynamic loads throughout the blowdown. The key parameters are the drywell and wetwell pressure, vent flow rates, and suppression pool temperature. The LOCA dynamic loads with the EPU include pool swell, condensation oscillation (CO), and chugging. For BSEP Mark I plants, vent thrust loads are also evaluated.

The licensee stated that the short-term containment response conditions for EPU are within the range of test conditions used to define the pool swell and condensation oscillation loads for the plant. The containment responses with EPU in which chugging would occur are within the conditions used to define the chugging loads. The vent thrust loads with the EPU are calculated to be less than the plant-specific values defined during the Mark I Containment LTP for BSEP. Therefore, the pool swell, condensation oscillation, chugging and vent thrust loads for the EPU remain bounded by the existing load definitions.

Based on its review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee's conclusion that the LOCA containment dynamic loads will remain acceptable after the EPU.

4.1.2.2 Safety/Relief Valve Loads

The safety-relief valve (SRV) air-clearing loads include SRV discharge line (SRVDL) loads, suppression pool boundary pressure loads, and drag loads on submerged structures. These loads are influenced by the SRV opening setpoint pressure, the initial water leg height in the SRVDL, the SRVDL geometry, and suppression pool geometry. For the first SRV actuations, the only parameter change which can affect the SRV loads that could be introduced by the EPU is an increase in the SRV opening setpoint pressure. This EPU does not include an increase in the SRV opening setpoint pressures; therefore, it has no effect on the loads from the first SRV actuations.

After SRV closure, water refloods the SRV discharge line, condenses steam, and creates a low pressure that causes the vacuum breaker to open, allowing water level in the discharge line to decrease. The licensee indicated that the current discharge load definition for SRV re-actuation used the maximum reflood height, which depends on the vacuum breaker capacity, SRVDL geometry and SRV setpoint. Because these parameters remain unchanged for the EPU, the existing load definition for SRV re-actuation also remains applicable to EPU conditions. Therefore, SRV loads remain bounded by the existing load definition.

Based on its review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee's conclusion that the EPU will have an insignificant impact on the SRV containment loads.

4.1.2.3 Annulus Subcompartment Pressurization

The licensee indicated that for the EPU, the temperature and enthalpy conditions increase slightly for each high energy line break (HELB) evaluated in the annulus, while the reactor operating pressure remains the same. This results in a slight increase in local subcompartment pressure due to the variation in fluid conditions. In a letter dated October 17, 2001, the licensee indicated that the analysis has determined that the peak pressures increased from 138.3 psia to 138.8 psia, which is less than a 0.4% increase. For the various HELBs analyzed, the largest increase in pressure was from 105.3 psia to 107.8 psia, or 2.4%. The biological shield wall remains adequate because the original analyzed loads include large conservatisms, which bound the uprated conditions by approximately 50%. Consequently, with an approximate 50% margin at current licensee thermal power, significant margin remains in the biological shield wall design with the small increase in pressure of 2.4% for EPU conditions. Therefore, the subcompartment pressurization will remain acceptable at EPU operation.

Based on its review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee's conclusion that plant operation at the EPU will have an insignificant impact on the annulus subcompartment pressurization.

4.1.3 Containment Isolation

The licensee indicated that the system designs for containment isolation are not affected by the EPU. The capability of the actuation devices to perform with the higher flow and temperature during normal operations and under post-accident conditions has been determined to be acceptable. Based on the review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee's conclusion that plant operations at the EPU will have an insignificant impact on the containment isolation system.

4.1.4 Generic Letter 89-10 Program

As discussed in GE NEDC-33039P and in CP&L's letter to the NRC dated January 24, 2002, the licensee evaluated the effect of the power uprate on the functionality of safety-related pumps and valves at BSEP. In considering the licensee's power uprate request, the NRC staff reviewed the licensee's submittals and discussed with the licensee the activities at BSEP to address the power uprate and its effect on safety-related pumps and valves in a telephone conference on February 14, 2002. For example, safety-related pumps at BSEP are adequately designed for operation at power uprate conditions because there will be no changes in the safety-related pump characteristics or assumed system response times. The licensee also evaluated the safety-related motor-operated valves (MOVs) within the scope of the program established in response to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." The NRC completed a detailed review of the GL 89-10 program at BSEP through a series of plant inspections. The NRC also accepted the licensee's MOV program in response to GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," through review of information submitted by the licensee. In evaluating the impact of the power uprate on its MOV program, the licensee found that the postulated post-LOCA containment environment associated with power uprate operations resulted in a small increase in the maximum expected differential pressure for 56 MOVs. The licensee will adjust the torque switch settings for two of those MOVs and will revise the design calculations for the other MOVs where torque switch adjustments are not necessary. The licensee is evaluating the air-operated valves at BSEP as part of an initiative similar to its GL 89-10 program for MOVs. The licensee has found the current design-basis differential pressure for air-operated valves that are subject to containment pressure to bound the predicted peak containment pressure assumed for the power uprate. Further, no adverse effects were identified regarding safety and relief valves in light of the absence of changes to reactor operating pressure under the power uprate conditions. The licensee also evaluated the impact of the power uprate on its response to GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The power-operated gate valves evaluated in response to GL 95-07 will not be adversely affected by potential pressure locking or thermal binding associated with the power uprate, because of the minimal pressure and temperature changes. The NRC staff finds the licensee's evaluation of the effect of the proposed power uprate on the capability of safety-related pumps and valves at BSEP to be acceptable, based on the NRC staff's previous review of the licensee's programs in response to GLs 89-10, 95-07, and 96-05, and the current review of the information submitted by the licensee describing the scope, extent, and results of the evaluation of safety-related pumps and valves at BSEP.

4.1.5 Generic Letter 96-06

The licensee confirmed in its January 24, 2002, letter that pressure relief venting devices installed in three identified penetrations in response to GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Condition," were not affected by the proposed power uprate. Therefore, the licensee concluded that the proposed power uprate has no impact on its evaluation in response to GL 96-06 in regard to potential over-pressurization of isolated piping segments for BSEP. The NRC staff finds the licensee's conclusion acceptable.

The licensee indicated that the plant's past response to GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," was reviewed for EPU post-accident conditions. BSEP is participating in an industry collaborative project with EPRI and the Nuclear Energy Institute (NEI) to develop a generic technical basis to address waterhammer issues described in GL 96-06. By a letter dated August 20, 1999, BSEP is committed to provide an update of intended actions with respect to GL 96-06 after the NRC staff approves the EPRI/NEI generic technical basis. Post-EPU containment temperatures and pressures will be used in any technical analyses developed to support the GL 96-06 evaluation.

Based on the above review, the NRC staff finds that the GL 96-06 requirements will be met for the EPU conditions.

4.2 <u>Emergency Core Cooling Systems</u>

The ECCS components are designed to provide protection in the event of a LOCA due to a rupture of the primary system piping. Although DBAs are not expected to occur during the lifetime of a plant, plants are designed and analyzed to ensure that the radiological dose from a DBA will not exceed the 10 CFR Part 100 limits. For a LOCA, 10 CFR 50.46 specifies design acceptance criteria based on the peak cladding temperature (PCT), local cladding oxidation, total hydrogen generation, coolable core geometry, and the long-term cooling. The LOCA analysis considers a spectrum of break sizes and locations, including a rapid circumferential rupture of the largest recirculation system pipe. Assuming a single-failure of the ECCS, the LOCA analysis identifies the break sizes that most severely challenge the ECCS systems and the primary containment. The MAPLHGR operating limit is based on the most limiting LOCA analysis, and licensees perform LOCA analyses for each new fuel type to demonstrate that the 10 CFR 50.46 acceptance criteria are met.

The ECCS for BSEP Units 1 and 2 include the HPCI system, the low-pressure coolant injection (LPCI) mode of RHR, the low pressure core spray (CS) system and the automatic depressurization system (ADS). ECCS performance is discussed in Section 4.3.

4.2.1 High-Pressure Coolant Injection System

The HPCI system (with other ECCS systems as backups) is designed to maintain reactor water level inventory during small and intermediate-break LOCAs and isolation transients. The HPCI system also serves as a backup to the RCIC system to provide makeup water in the event of a LOFW transient.

The licensee evaluated the BSEP Units 1 and 2 HPCI system capability and performance for EPU operation. The HPCI system is designed to pump water into the reactor vessel over a wide range of reactor operating pressures. The maximum injection pressure for the HPCI system corresponds to the upper analytical setpoint for the lowest available group of SRVs, operating in the spring safety mode. Since the SRV setpoints and the normal operating dome pressure do not change for the EPU operation, the licensee stated that there is no change to the HPCI high pressure parameters.

The HPCI system is relied upon to maintain the reactor water level above the top of the active fuel and prevent ADS actuation for break sizes up to 1 inch in diameter. However, in the BSEP USFAR, HPCI is relied upon to maintain the reactor water level above the top of the active fuel and prevent ADS actuation for break sizes up to 1 inch in diameter. The ECCS-LOCA performance analyses are discussed in Section 4.3.

As a back-up to the RCIC system, the HPCI system also provides makeup water in the event of LOFW, with MSIV closure. The licensee determined that with a minimum allowed flow rate of 3825 gpm, the HPCI system can provide sufficient water to maintain the water level above the TAF. In this event, the reactor would scram, with the SRVs cycling to maintain the dome pressure within the maximum injection pressures and the HPCI system would return the water level to normal.

The licensee has implemented the turbine control modifications recommended by GE Service Information Letter (SIL) 480. These modifications minimize the effect of reactor pressure on: (a) the magnitude of the turbine peak initial speed, (b) the initial peak pump discharge pressure, and (c) the pump discharge flow rate. The modifications described in the SIL hydraulically limit the opening of the control valves during the initial startup period, thereby minimizing the potential for turbine overspeed. The licensee concluded and the NRC staff accepts that HPCI turbine operation with the EPU does not result in any changes to the startup transient or the system reliability.

For some beyond-design basis events (Appendix R fire and ATWS), the condensate storage tank (CST) provides a dedicated water source for the HPCI system.

For the EPU operation, the licensee evaluated the capability of the HPCI system to provide core cooling to the reactor and maintain the water level above the TAF following a LOCA for break sizes up to 1 inch, and LOFW transient. The licensee concluded that since there is no pressure increase associated with the EPU, the HPCI operating conditions and performance are not affected for BSEP Units 1 and 2.

Although the EPU does not increase the operating dome pressure, the reactor can experience higher pressures during isolation transients for the EPU operation. However, since the licensee found that the BSEP Units 1 and 2 have sufficient capacity to maintain the reactor pressure within the design operating range of the HPCI system, the NRC staff accepts the licensee's assessment for the HPCI system's performance at the EPU conditions.

Based on the information submitted and the review of the licensee's evaluation, the NRC staff concludes that HPCI is acceptable for the EPU operation.

4.2.2 Low-Pressure Coolant Injection System

The LPCI mode of the RHR system is automatically initiated in the event of a LOCA, and in conjunction with other ECCS systems, the LPCI mode is used to provide adequate core cooling for all LOCA events.

The licensee evaluated the effects of the EPU operation on the LPCI system's performance and stated that the increase in the decay heat due to the EPU operation could increase the calculated PCT. The licensee stated that the ECCS-LOCA performance evaluation for BSEP Units 1 and 2 demonstrates that the existing LPCI capability, in conjunction with other ECCS, is adequate to meet the post-LOCA core cooling requirements for the EPU conditions. The licensee added that the RHR LPCI mode is bounded by the generic evaluation provided in Section 4.1 of ELTR2.

Based on the information submitted and the licensee's ECCS-LOCA analysis results (see Section 4.3 of this SE), which demonstrate that the LPCI (with other ECCS) provides adequate core cooling, the NRC staff concludes that LPCI system performance at the EPU conditions is acceptable.

4.2.3 Core Spray System

The low pressure CS system initiates automatically in the event of a LOCA, and in conjunction with other ECCS systems, the CS system provides adequate core spray cooling and flooding for all LOCA events.

The licensee stated that while the calculated LOCA PCT could increase slightly at the uprated power level, the existing CS system combined with other ECCS systems will provide adequate long-term post-LOCA core cooling. The licensee stated that the ECCS performance evaluation for BSEP Units 1 and 2 demonstrates that the existing low pressure CS performance capability in conjunction with other ECCS is adequate to meet the post-LOCA core cooling requirements for the EPU operation. The licensee determined that the existing CS hardware capabilities are sufficient to provide the required CS injection function for the EPU operation. In addition, the BSEP Units 1 and 2 CS system performance is bounded by the generic evaluation in Section 4.1.1 of ELTR2, Supplement 1.

Based on the information submitted and the licensee's ECCS-LOCA analysis (see Section 4.3 of this SE), which demonstrates the CS system's capability at the EPU conditions, the NRC staff concludes that BSEP Units 1 and 2 CS system provides adequate core spray cooling and flooding.

4.2.4 Automatic Depressurization System

The ADS uses seven SRVs to reduce reactor pressure following a small-break LOCA, allowing the LPCI and the low pressure CS systems to provide core spray cooling and flooding. The plant design requires the SRVs to have a minimum flow capacity. After a specified delay, the ADS initiates on low water level (LL1/L3) and either one CS or both RHR pumps in one loop are running. The licensee stated that the ability of the ADS to initiate on appropriate signals is not affected by the power uprate. The licensee determined that the initiation logic and the ADS valve control are not affected by the EPU operation. The licensee concluded that the ECCS-LOCA analyses (assuming failure of the high pressure systems) demonstrate that the ADS capacity is adequate when operating at the EPU conditions.

The BSEP Units 1 and 2 ECCS-LOCA analyses assume that for small and intermediate break sizes the ADS would depressurize the reactor to the injection capabilities of the low pressure ECCS system. The BSEP units are also licensed with one ADS valve out of service (ADS-OOS). The NRC staff asked the licensee to verify that the ECCS-LOCA analysis relying on the ADS to depressurize the reactor assumed failure of 2 ADS valves (1 ADS single failure and 1 ADS- OOS.) The licensee confirmed that the ECCS-LOCA analysis relying on the ADS assumes that five of the seven ADS valves were operable.

Since the licensee's ECCS-LOCA analysis results (see Section 4.3 of this SE) demonstrate that with five ADS valves out of seven operating the ADS had sufficient capacity to reduce the reactor pressure to the low pressure injection level, the NRC staff concludes that the ADS is acceptable for the EPU operation.

4.2.5 Net Positive Suction Head

EPU operation increases the peak suppression pool water temperature and containment pressure during the post LOCA, long-term RHR and CS pump operation as indicated in Section 4.1.1 "Containment Pressure and Temperature Response" of NEDC 33039P-A. BSEP currently is committed to the provisions of the Safety Guide 1 (Regulatory Guide 1.1), "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps." As a result, no credit is currently taken for containment pressure when performing ECCS NPSH calculations. Due to the proposed EPU, the licensee is revising this commitment to take credit for containment overpressure as indicated below to assure adequate NPSH for RHR and CS pumps following a DBA LOCA. Post-LOCA NPSH concerns are not applicable to the HPCI system.

<u>Short-Term NPSH Requirements</u> - The licensee indicated that for short-term post-LOCA operation (i.e., 0 to 600 seconds), no operator action is credited and, as a result, the RHR and

CS pumps are assumed to be at runout conditions. The peak suppression pool temperature at 600 seconds (i.e., short-term) was calculated to be 169.1°F. The RHR and CS pumps have NPSH margins of +4.1ft and +6.4ft, respectively. Therefore, for short-term NPSH requirements, no containment overpressure credit is required.

Long-Term NPSH Requirements - The licensee indicated that for long-term post-LOCA operation (i.e., greater than 600 seconds), operator action to throttle the RHR and CS pumps is assumed. As such, the assumed pump flows are 5,775 gpm per RHR pump (11,550 gpm loop flow) and 4,725 for each CS pump. For EPU, a re-analysis of the primary containment response to pipe breaks was performed for NPSH. The re-analysis was performed both with and without crediting containment spray. The case that did not credit containment spray produced the peak temperature response of 207.7°F with a corresponding pressure of 25.5 psig. However, the case that credited containment spray produced a slightly lower temperature profile (i.e., 206.8°F peak) and a much lower pressure profile (i.e, 11.3 psig peak). For conservatism, the NPSH calculations were performed based on the containment spray case, with the containment spray temperature profile increased by 0.9°F such that the peak temperature equaled that of the no-spray case. Using the conservative profile discussed above, the NPSH parameters were determined for bounding conditions.

The summarized results of the NPSH margin and containment pressure verses time are provided in Enclosure 7, Tables 7-1 and 7-2 of the licensee submittal dated August 9, 2001. The maximum required overpressure needed to ensure NPSH is 3.1 psig (7.5 ft) for the RHR pump and 2.6 psig (6.3 ft) for the CS pump, with 11.3 psig (27 ft) containment overpressure available. In all cases, the available containment overpressure is in excess of three times the amount required to ensure adequate NPSH. Therefore, adequate NPSH margin exists for the low pressure ECCS pumps.

To ensure sufficient margin exists to address potential future issues, the licensee credited a containment overpressure of up to 5.0 psig be credited for calculating ECCS pump NPSH margins. This re-analysis will become the new licensing basis for the primary containment response to pipe breaks and Section 6.2.1.1.3 of the BSEP UFSAR will be revised accordingly.

The NRC staff has reviewed the licensee's rationale, calculation, and evaluation for ECCS NPSH requirements and minimum containment overpressure available as indicated above in licensee submittals, and finds the requested containment overpressure credit of up to 5.0 psig for NPSH requirements from the available post-LOCA containment pressure of 11.3 psig acceptable for the EPU.

4.3 Emergency Core Cooling System Performance Evaluation

The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in the primary system piping. The ECCS performance under all LOCA conditions and the analysis models must satisfy the requirements of 10 CFR 50.46 and 10 CFR Part 50, Appendix K.

4.3.1 ECCS-LOCA Codes and Methodology

The ECCS-LOCA analysis is performed in accordance with the NRC-approved methodology specified in GE's licensing document GESTAR II. For each plant, a base ECCS-LOCA analysis with a full-scope break spectrum forms the initial SAFER/GESTR-LOCA analysis-of-record for the rated power level. For introduction of a new fuel design, the licensee performs an ECCS-LOCA analysis (a subset of the full-scope spectrum) in accordance with Amendment 22 of

GESTAR II to demonstrate compliance with 10 CFR 50.46 and 10 CFR 50, Appendix K requirements, or the licensee demonstrates that the existing fuel design ECCS-LOCA analysis remains applicable and bounding. During reload analyses, the licensee evaluates the cycle-specific MAPLHGR limits to confirm that the MAPLHGR limit based on the ECCS-LOCA analysis-of-record remains bounding.

The BSEP Units 1 and 2 base ECCS-LOCA analysis with full-scope break spectrum analysis is documented in NEDC-31624P, "Brunswick Steam Electric Plant Units 1 and 2 SAFER/GESTAR-LOCA Loss-of-Coolant Accident Analysis," published in July 1990. The licensee performed a subset of these ECCS-LOCA analyses for the introduction of GE13 fuel to Units 1 and 2. CP&L subsequently introduced GE14 fuel to Unit 2 in March 2001, during the Cycle 15 reload and performed the GE14 ECCS-LOCA analysis at the CRTP. The GE ECCS-LOCA analysis is based on the NRC-approved SAFER/GESTAR-LOCA methodology performed using a series of NRC-approved codes: SAFER, LAMB, GESTR, and TASC.

The SAFER code is used to calculate the long-term thermal-hydraulic behavior of the coolant in the vessel during a LOCA. Some important parameters calculated by SAFER are vessel pressure, vessel water level, and ECCS flow rates. The SAFER code also calculates PCT and local maximum oxidation.

The LAMB code is used to analyze the short-term thermal-hydraulic behavior of the coolant in the vessel during a postulated LOCA. In particular, LAMB predicts the core flow, core inlet enthalpy, and core pressure during the initial phase of the LOCA event (i.e., the first 5 seconds).

The GESTR code is used to provide best-estimate predictions of the thermal performance of GE nuclear fuel rods experiencing variable power histories. For LOCA analysis, the GESTR code is used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA.

TASC has been accepted for the transient analysis and LOCA analyses. TASC is a detailed model of an isolated fuel channel. TASC is an improved version of the NRC-approved SCAT code, with the added capability to model advanced fuel features (partial length rods and new critical power correlation). It is used to predict the time-to-boiling transition for a large-break LOCA. This value is used in subsequent codes to turn off nucleate boiling heat transfer models and turn on transition boiling models.

4.3.2 ECCS-LOCA Deviations

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]. This [ ] ECCS-LOCA approach would consider the impact of the power uprate on the PCT in the same manner that the impact due to a change or error is reported under 10 CFR 50.46. [

]. The ECCS-LOCA deviation also requires that there be no additional changes that might affect the EPU ECCS-LOCA response, such as implementation of higher rod line or new fuel introduction.

The NRC staff audited the BSEP Unit 2 ECCS-LOCA analysis deviation. The NRC staff's ECCS-LOCA RAIs generated during the audit provide the details of the actual ECCS-LOCA analysis performed, the technical basis that justifies the [ ] analysis and the ECCS-LOCA deviation's compliance with the regulatory requirement and the NRC-approved SAFER/GESTAR-LOCA methodology. A description of the [ ] ECCS-LOCA analysis performed for BSEP Unit 2, a summary of the licensee's justification of the adequacy of the approach, the compliance of the ECCS-LOCA deviation with 10 CFR 50, Appendix K requirements, and the NRC staff's evaluation of the ECCS-LOCA deviation follow.

1. [

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2. [

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3. Appendix K of 10 CFR 50 requires that a spectrum of possible break sizes be considered. [ ]

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Therefore, the NRC staff accepts the licensee's assessment that BSEP Unit 2 EPU ECCS-LOCA analysis meets the requirement in 10 CFR 50, Appendix K.I.C.1.

4. [

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Based on the ECCS-LOCA approach discussed above, the licensee reported a licensing basis PCT of less than 1557°F for the EPU power level compared to a PCT of 1560°F for the CRTP power level for BSEP Unit 2. The Appendix K PCT for the EPU operation is calculated at 1.02 percent of the EPU power level (2982 MWt) and the GE14 new fuel introduction ECCS-LOCA analysis is based on 2679 MWt or 110% of the ORTP. Table 4-2 also shows that BSEP Unit 2 complies with the other acceptance criteria of 10 CFR 50.46 (local cladding oxidation, core-wide metal-water reaction, coolable geometry). Therefore, based on the on-site audit of the ECCS-LOCA approach and results for BSEP Unit 2, the licensee’s use of approved methodologies, and the technical justification provided in the licensee's RAI responses, the NRC staff accepts the EPU ECCS-LOCA analysis for BSEP Unit 2.

The licensee introduced GE14 fuel design in Unit 1 in the Cycle 14 reload in March 2002. However, the ECCS-LOCA analysis approach is based on factoring out all other changes that impact the plant's ECCS-LOCA response and evaluating only the impact due to the power increase. In addition, both the [ ] EPU ECCS-LOCA analysis and the GE14 fuel introduction analysis performed at the CRTP are based on Unit 2. Therefore, the NRC staff asked the licensee to explain why the ECCS-LOCA analyses for Unit 2 bounds Unit 1 and why the ECCS-LOCA analysis is applicable to Unit 1. Based on the documents reviewed during the audit and the licensee's RAI response, the reasons why the Unit 2 limited ECCS-LOCA analysis bounds Unit 1 are discussed below.

1. The units have a similar ECCS system network (trains and available systems assuming single failure) and ECCS capacity (i.e low pressure ECCS and ADS capacities). Due to these similarities, the two units would be expected to exhibit a similar ECCS-LOCA response. However, Unit 2 has more restrictive side-entry orifices, which would result in lower initial flow through the hot bundle. Consequently, the hot channel in Unit 2 would experience boiling transition (BT) earlier during a DBA recirculation line break. This is not due to core uncovery, but to insufficient bundle flow to maintain the upper portions of the rods in the hot bundle wetted during the first few seconds of the event. The hot bundles are assumed to be operating at the peak LHGR limit and considering the same nodal power, roughly similar local fluid conditions. The bundle with the lower flow will be closer to BT. The vapor blanket will decrease the heat transfer coefficient, resulting in heatup of the upper portion of the rods in the hot bundle. The hot bundle in Unit 2 would experience a higher first peak PCT in the first seconds into the event. The second PCT peak can also be higher, because the fuel bundle heatup following uncovery would occur with the rods in the hot bundle at higher temperature. Therefore, the PCT for Unit 2 would bound the PCT for Unit 1 for the DBA recirculation line break. For the small break LOCA, the units are expected to have a similar response, because (1) the vessel does not depressurize through the break, (2) there would be a longer flow coastdown (both recirculation pumps would trip and no dryout would occur), and (3) the ADS and the low pressure ECCS system capacity are similar for both units. The licensee stated that in the initial SAFER/GESTR-LOCA analysis-of-record, licensing basis PCT was 4°F lower and the upper bound PCT was 37°F lower for Unit 1 compared to Unit 2.

2. To determine if the Unit 2 EPU limited ECCS-LOCA analysis at the EPU condition bounds Unit 1, the NRC staff evaluated the effects the similarities and differences between the units would have on their ECCS-LOCA response. The NRC staff also reviewed the core flow range used to evaluate the ECCS-LOCA analysis. In the GE methodology, if the plant is not MAPLHGR-limited and has sufficient PCT margin, a [ ] ECCS-LOCA analysis at 100-percent core flow will be performed. Both BSEP units would be able to achieve the 100-percent core flow, with the minimum core flow being approximately 99 percent. The units are also not MAPLHGR-limited. In addition, due to the channeled configuration of BWR fuel assembly, there is no bundle to bundle cross flow inside the core and the GE13 and GE14 fuel are thermal-hydraulically compatible. Thus, the ECCS-LOCA analyses are performed separately for each fuel design (GE14 or GE13). The assumed key input assumptions and conditions (i.e the hot bundle operates at the peak LHGR, as well as at the operating limit MCPR) in ECCS-LOCA analysis are set conservatively so as to avoid performing an ECCS-LOCA analysis every reload. Therefore, cycle-specific ECCS-LOCA analyses are not performed. Based on the similarities of the ECCS-LOCA systems, the technical rationale discussed above, and the use of approved methodologies to perform the evaluations, the NRC staff accepts the licensee's assessment that the ECCS-LOCA response of the two units would be similar, or Unit 2 would bound Unit 1. Therefore, the NRC staff accepts the licensee's position that the ECCS-LOCA analysis performed for Unit 2 is applicable to Unit 1.

The licensee stated that the ECCS-LOCA analysis performed at the CRTP to support the GE14 introduction to Unit 2 for Cycle15 is applicable to Unit 1, Cycle 14. In other words, the GE14 ECCS-LOCA analysis-of-record for operation of Unit 1 at the CRTP would be the Unit 2 GE14 ECCS-LOCA analysis. The NRC-approved Amendment 22 to GESTAR II requires that for a new fuel design, either a new ECCS-LOCA analysis should be performed or an applicable bounding analysis should be used to demonstrate that the new fuel design complies with the requirements in 10 CFR 50.46 and 10 CFR 50, Appendix K. Since the Unit 2 GE14 ECCS-LOCA analysis at the CRTP can be reasonably characterized to be at least applicable, if not bounding, for Unit 1, the NRC staff accepts that the Unit 2 GE14 ECCS-LOCA analysis represents the GE14 ECCS-LOCA response for Unit 1. The existing analysis ensures that operation of the GE14 fuel in Unit 1 at the CRTP would meet the applicable regulatory requirements.

Based on the information submitted, the audit of the ECCS-LOCA analysis approach, the licensing basis PCT margin (1557°F / 2200°F) available, the responses to the RAIs, the use of approved methodologies to perform the evaluations, and the fact that the licensee will verify that key ECCS-LOCA input parameters such as the OLMCPR and MAPLHGR will continue to remain bounding on a cycle-specific basis, the NRC staff accepts the licensee's ECCS-LOCA performance evaluation for BSEP Units 1 and 2 EPU operation.

4.4 Main Control Room Atmosphere Control System

The licensee stated in a submittal dated August 9, 2001, that the main control room atmosphere Control System (MCRACS) is not significantly affected by the EPU and control room operator doses remain well below regulatory limits**.** The licensee further stated that in Section 9.2 of NEDC-33039, Rev. 0, the radiological consequences of the LOCA and non-LOCA DBAs have been reviewed for the effect of the EPU using the guidance of RG 1.183 alternative source term

(AST)[1], and the results are within the guidelines of 10 CFR 50.67 and GDC-19 of 10 CFR 50, Appendix A. Because the licensee performed its evaluation against the standards of GDC-19, the staff also used GDC-19 to evaluate the acceptability of the application.

On September 17, 2001, the NRC provided an electronic version of an RAI regarding the potential impact of the EPU on those heating, ventilation, and air conditioning (HVAC) systems discussed in NUREG-0800, "Standard Review Plan," Sections 6.4, 6.5.1, and 9.4.1. Also, the NRC staff requested that the licensee include a discussion of the impact, if any, during both normal and post-accident operations resulting from increased heat loads due to the EPU and the bases for CP&L's determination of control room emergency ventilation system (CREVS) acceptability post-EPU. The licensee responded as follows:

- The Control Building HVAC systems: The control building HVAC systems consist of the CREVS, cable spreading room HVAC system, and battery room HVAC system.

- CREVS:

  - The system supports the control room, including the back-panel area. The heat loads in this area are the electrical equipment in the control room back-panel area and the control room staff. There are no changes to heat loads inside the control room and only minor changes in adjacent areas.

  - The iodine loading on the CREVS charcoal beds is calculated to be 1.24 E-7 mg/gram of charcoal, which is a small fraction of the 2.5 mg/gram design limit identified in RG 1.52, Revision 1, 1976. As such, CREVS charcoal effectiveness is not impacted by EPU. Therefore, the Control Room portion of Control Building HVAC system, including CREVS, is not affected by EPU.

- Cable Spreading Room HVAC System: The system is a separate once-through system and is minimally affected by EPU. A portion of the condensate piping runs through the control building cable spreading room area, which represents an increased heat load under EPU conditions. This increase was conservatively evaluated to be less than 2°F, well within the capability of the current HVAC system.

- Battery Room HVAC System: The system is a separate once-through system. DC loads in the battery rooms were reviewed and calculated to increase by less than 1% for normal and post-accident power loading under EPU conditions. Therefore, the effects of EPU are insignificant for the Battery Room HVAC system.

Based upon the above, the NRC staff finds that Brunswick Units 1 and 2 comply with the regulatory requirements of 10 CFR Part 50, Appendix A, GDC-19, guidance of GL 99-02, and guidelines of RG 1.52 and NUREG-0800, "Standard Review Plan," Sections 6.4, 6.5.1, and 9.4.1.

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[1] The licensee requested NRC approval for use of the AST in a separate amendment. Approval of the amendment was a necessary prerequisite for approval of the EPU. The NRC staff approved the amendment allowing use of the AST on May 30, 2002.

Based on its review of the licensee's rationale, and the experience gained from its review of power uprate applications for other BWR plants, the NRC staff concludes that the EPU does not adversely affect the operation of the Control Building HVAC system.

4.5 Standby Gas Treatment System

The licensee stated in a submittal dated August 9, 2001, that in Section 9.2 of NEDC-33039, Rev. 0, the radiological consequences of the plant design-basis LOCA and non-LOCA have

been reviewed for the effect of the EPU using the guidance of RG 1.183 AST, and the results are within the guidelines of 10 CFR 50.67. The licensee provided information as follows for the standby gas treatment system (SGTS):

- The SGTS is designed to minimize off-site and control room doses during venting and purging of the primary and secondary containment atmospheres under accident or abnormal conditions.

- The (design flow capacity) of the system was selected to maintain the secondary containment at the required negative pressure to prevent exfiltration of air from the reactor building. This capability is unaffected by the EPU.

- The charcoal filter bed removal efficiency for radioiodine is also not affected by the EPU. As a result of the EPU and the application of AST derived from RG 1.183, the post-LOCA total iodine loading decreases from 2.1 to 0.003 mg/gm of charcoal at the EPU conditions, which is well below the RG 1.52 value. Therefore, the SGTS contains sufficient charcoal to ensure iodine removal efficiencies greater than the current design requirement.

On September 17, 2001, the NRC provided an electronic version of an RAI regarding the potential impact of EPU on those HVAC systems discussed in SRP Sections 6.5.1 and 9.4.5. Also, NRC staff requested that the licensee include a discussion of the impact, if any, during both normal and post-accident operations resulting from increased heat loads due to the EPU and the bases for CP&L's determination of SGTS system acceptability post-EPU. The licensee responded in a letter dated October 17, 2001, as follows:

- As discussed in Section 4.5 of the PUSAR, SGTS is not affected by EPU.

- The design capacity of the SGTS is not changed by the EPU. As a result of the EPU and the application of the AST derived from RG 1.183, the post-LOCA total iodine loading decreases from 2.1 to 0.003 mg/gm of charcoal, which is well below the original design capacity and below that recommended by RG 1.52. The SGTS retains its capability of meeting its design basis requirement for mitigation of offsite doses following a postulated design basis accident.

- The post-accident decay heating of the SGTS, and any resultant heat load on HVAC systems, is evaluated to decrease for EPU conditions as a result of application of the AST.

Based upon the above, the NRC staff finds that Brunswick Units 1 and 2 continue to comply with the regulatory guidance of 10 CFR 50.67 and the guidelines of Regulatory Guide 1.52, and Sections 6.5.1 and 9.4.5 of NUREG-0800.

Based on its review of the licensee's rationale, and the experience gained from its review of power uprate applications for other BWR plants, the NRC staff concludes that the proposed EPU does not adversely affect operation of the SGTS.

4.6 Main Steam Isolation Valve Leakage Control System

This is not applicable to BSEP Units 1 and 2 because the plant does not use a main steam isolation valve leakage control system.

4.7 Post-LOCA Combustible Gas Control System

The licensee indicated that the combustible gas control system is designed to maintain the oxygen concentrations of the drywell and containment atmospheres below the lower flammability limit following a LOCA. The containment atmosphere control system consists of the containment inerting subsystem and the containment atmospheric dilution (CAD) subsystem. The CAD system is designed to engineered safety features standards and for maintaining the oxygen concentration in the containment below the limit of 5 percent by volume in accordance with RG 1.7 (Safety Guide 7), "Control of Combustible Concentrations in Containment Following a Loss-of-Coolant Accident." Design of the system is based on the production of hydrogen from 1) metal-water reaction of active fuel cladding, 2) corrosion of zinc and aluminum exposed to water during a postulated LOCA, and 3) radiolysis of water. Only post-LOCA production of hydrogen and oxygen from radiolysis will increase in proportion to the power level. In a letter dated October 17, 2001, the licensee indicated that new fuel designs are not needed for the EPU to provide additional safety. The EPU evaluations considered GE13 and GE14 fuel types in all accident analyses.

The licensee indicated that the increase in radiolysis due to the EPU has a minor impact on the time available to start the system before reaching procedurally controlled limits, but does not impact the ability of the system to maintain oxygen below the lower flammability limit of 5% by volume in the drywell and the containment atmosphere as specified in Safety Guide 7. For the EPU, the minimum required start time for the CAD system decreases from 6.2 days to 5.3 days after LOCA. The reduction in required CAD initiation time does not affect operator functions.

The CAD tank has a nitrogen storage capacity of 5000 gallons. Of this, 4350 gallons are provided per TS for maintaining the oxygen concentration limits in the primary containment. The additional 15%, or 650 gallons, is provided for losses and process margin. The licensee indicated that CAD on-site nitrogen storage volume is adequate to maintain the containment atmosphere at or below the 5% oxygen flammability limit for 29 days post-LOCA after the EPU, as compared to a minimum of 30 days for current conditions. This change is not significant and allows adequate time to replenish the storage tank from off-site sources. Analysis of the containment pressure buildup as a result of continuing CAD operation shows that the containment repressurization limit of 31 psig (50% of the design pressure) is not exceeded until 29 days after the LOCA. The analysis uses the conservative assumptions of zero containment leakage and an initial oxygen concentration equal to the allowable TS limit of 4%. More realistic analyses using typical initial inerting levels of approximately 1% oxygen and containment leakage below the allowable 0.5% per day extend both the available nitrogen supply and the approach to the repressurization limit to over 30 days.

Based on NRC staff review of the licensee's rationale and evaluation, the NRC staff finds the deviation in storage capacity as indicated above acceptable and agree with the licensee's conclusion that plant operations at the proposed uprate power level will have a minor impact on the post-LOCA combustible gas control system and the system will remain acceptable at the EPU conditions.

5.0 INSTRUMENTATION AND CONTROL

Background

In addition to proposed TS changes that address existing margins in the TS, the licensee will be physically modifying BSEP Units 1 and 2 to accommodate an initial 5 to 10 percent RTP increase for each unit. The planned modifications are as follows:

1. First Load of GE14 Fuel (Unit 1). Unit 2 loaded the first batch of GE14 fuel during the Spring 2001 refueling outage.

2. High-Pressure Turbine Replacement and Electro-Hydraulic Control Admission Mode Change

3. Main Generator Rewind (Unit 1). This modification was completed on Unit 2 during the Spring 2001 refueling outage.

4. Reactor Feedwater Pump Turbine Replacement.

5. Isophase Bus Cooling Upgrade (Unit 1).

6. Out-of-Step Relay and Blocking Modification. This modification addresses grid stability issues under EPU conditions.

7. Feedwater Heater Replacement. Unit 1 will require replacement of feedwater heaters 5A and 5B to support the initial uprate. Unit 2 does not require replacement of any feedwater heaters to support the initial uprate. However, feedwater heater 4B, whose replacement is required to support the full Unit 2 uprate, will be replaced during the Spring 2003 refueling outage.

8. Generator Lockout Load Shed Modification. This modification assures adequate loss-of-coolant accident voltage support following a generator lockout.

9. Nuclear Instrumentation Upgrade. This modification results in a revision to the BSEP long-term solution to thermal-hydraulic stability from the existing BWROG Enhanced Option I-A long-term solution to the BWROG Option III solution. The licensee has requested, via a separate submittal, a license amendment request. This was approved and issued as Amendment 217 for BSEP Unit 1 and Amendment 243 for BSEP Unit 2.

10. Main Steam and Feedwater Vibration Monitoring Instrumentation.

11. Potential Modifications Supporting Alternative Source Term Implementation.

Modifications supporting the full uprate to 2,923 MWT for each unit are as follows:

1. SLC Upgrade. The SLC upgrade supports the transition to the GE14 fuel design, which is necessary to achieve the full EPU. This modification is not required until the second reload with GE14 fuel on each unit. As such, the licensee will submit separate from the EPU submittal associated license amendments revising the sodium pentaborate solution concentration requirements contained in Technical Specification 3.1.7, “Standby Liquid Control (SLC) System.” Since Unit 2 has already had one reload using GE14 fuel, the licensee will require this amendment in Spring 2003, to support the initial Unit 2 uprate.

2. Stator Cooling Water Upgrade.

3. Power System Stabilizer. This modification will provide feedback to the voltage regulator to dampen oscillations following grid disturbances.

4. Isophase Bus Cooling Upgrade.

5. Main Transformer Replacement/Rewind.

6. Condensate System Upgrade.

7. Feedwater Heater Replacement. Unit 1 will require replacement of feedwater heaters 3A, 3B, and 4A to support the final uprate. Unit 2 will require replacement of feedwater heater 4B (which will be performed during the Spring 2003 refueling outage) to support the final uprate.

8. Moisture Separator Reheater (MSR) Upgrade.

9. Reactor Building Component Cooling Water System Heat Exchanger Retubing (Unit 1).

10. Condensate Filter Demineralizer (CFD) Upgrade. This modification will install longer filter elements to increase CFD filter element life.

11. MSR Relief Valve Modifications. This modification will implement higher setpoints and allow greater capacity.

12. Reactor Feed Pump Upgrade.

13. Condensate Cooling Modification.

The effects of these modifications on NSSS monitoring and control systems, BOP monitoring and control systems, instrumentation setpoints and calibrations, allowable values (AVs), analytical limits (ALs), and the TS are addressed in Sections 5.2, 5.3, and 5.4. Section 5.4, Conclusions, summarizes the NRC staff safety evaluation conclusions.

The safety-related and major (non-safety) process monitoring instruments, controls and trips (analytical limits for setpoints) that could be affected by the EPU are addressed in this section.

Sections 5.1, NSSS Monitoring and Control Systems, and 5.2, BOP Monitoring and Control Systems, address the actions taken by the licensee regarding the non-safety-related NSSS monitoring and control systems and balance of plant monitoring and control systems, respectively, that could affect plant safety-related systems. Section 5.3 , Instrumentation Setpoint Evaluation, addresses the licensee's proposed changes of instrumentation setpoints for

the BSEP reactor protection system and the engineered safety features systems as a result of the EPU. Section 11.2, Technical Specifications, addresses the licensee's proposed TS changes within the scope of this safety evaluation.

5.1 NSSS Monitoring and Control Systems

The instrumentation and controls that directly interact with or control the reactor are usually evaluated with the NSSS. The licensee evaluated the NSSS process variables, instrument setpoints, and RG 1.97 instrumentation that could be affected by the EPU. As part of the EPU implementation, the licensee used accepted setpoint methodologies to generate the AVs related to the AL changes addressed in the licensee's submittal. The following discussion summarizes the results of the licensee's NSSS evaluations and the NRC staff's conclusions regarding those evaluations.

5.1.1 Control Systems Evaluation

The licensee evaluated changes in process variables and their effects on instrument setpoints for the EPU operation to determine any related changes. The licensee stated that process variable changes will be implemented through changes in plant procedures. The NRC staff finds acceptable this process for changing process variables by using plant procedures.

TS instrument allowable values and/or setpoints are those sensed variables that initiate protective actions. The licensee stated that determination of instrument AVs and setpoints is based on NRC staff-approved methodologies, plant operating experience, and the conservative ALs used in specific licensing safety analyses. The licensee selected settings to ensure sufficient margin exists to preclude inadvertent initiation of the protective action, while assuring that adequate operating margin is maintained between the system settings and the actual limits. The licensee's use of NRC-approved setpoint methodologies in setting margins between system settings and actual limits is acceptable.

Increases in the core thermal power and steam flow affect some instrument setpoints, as described in Section 5.3 of ELTR1. The licensee adjusted these setpoints to maintain comparable differences between system settings and actual limits, and reviewed the setpoints to ensure that adequate operational flexibility and necessary safety functions are maintained at the EPU RTP level. The NRC staff finds acceptable this process for reviewing setpoints relative to operational considerations.

5.1.2 Neutron Monitoring System

The licensee will scale the average power range monitor (APRM) power signals to the EPU RTP level, such that the indications read 100% at the new licensed power level. This scaling is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

The licensee stated the EPU implementation will have little effect on the overlap between the intermediate range monitors (IRMs) and the source range monitors (SRMs) and the APRMs. Using normal plant surveillance procedures, the licensee will adjust the IRMs, as required, so that overlap with the SRMs and APRMs remains adequate. No change is needed in the APRM downscale setting. The NRC staff finds these actions acceptable.

The licensee stated the neutronic life of the local power range monitor (LPRM) detectors and radiation levels of the Traversing In-Core Probe (TIP) detectors/cables may be affected slightly due to the higher power level. The licensee concluded that the effect of the higher power level is expected to be too small to affect LPRM or TIP performance. The NRC staff concurs with this conclusion.

The licensee stated that the Rod Block Monitor (RBM) instrumentation is not affected by the EPU conditions, and thus, no change is needed. This conclusion is consistent with the guidance and conclusions provided in ELTR1 and, therefore, is acceptable.

5.1.3 Rod Worth Minimizer

The Rod Worth Minimizer (RWM) does not perform a safety-related function. The function of the RWM is to support the operator by enforcing rod patterns until reactor power has reached an appropriate level (e.g., the low power setpoint (LPSP)). Specifically, the RWM satisfies Criteria 3 of 10 CFR 50.36 and functions to limit the local power in the core to maintain the effects of the postulated Control Rod Drop Accident (CRDA) while reactor power is <10% of Current Licensed Thermal Power (CLTP) and <8.75% of the EPU RTP. This revised RWM setpoint is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.2 <u>BOP Monitoring and Control Systems</u>

The licensee stated that operation of the plant at the EPU RTP level has minimal effect on the BOP system instrumentation and control devices. Based on the EPU operating conditions for the power conversion and auxiliary systems, the licensee concluded that most process control values and instrumentation have sufficient range/adjustment capability for use at the expected EPU conditions. However, some (non-safety) modifications of the power conversion systems may be needed to obtain full EPU RTP. No safety-related setpoint change in the BOP is required as a result of the EPU. The NRC staff finds this conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.2.1 Pressure Control System

The Pressure Control System (PCS) provides fast and stable responses to system disturbances related to steam pressure and flow changes to control reactor pressure within its normal operating range. The PCS consists of the pressure regulation system, the turbine-generator (T/G) electro-hydraulic control (EHC) system, and the steam bypass valve system. The main turbine speed/load control function is performed by the EHC system. The steam pressure control function is performed by the pressure regulation system through manipulation of the turbine control valves (TCVs) and the bypass valves.

The turbine inlet pressure is an important parameter in determining the operating point on the turbine control valves. Adequate control valve range must be available to ensure the ability of the PCS to respond to system disturbances requiring steam flow changes to minimize pressure excursions. With modifications such as changes to the high-pressure turbine and adjustments to the turbine control valve diode function generators (DFGs) in the EHC, the licensee concluded that sufficient pressure control range will be available to control system disturbances at the EPU conditions. Thus, the existing main T/G EHC, the pressure regulation system, and the steam bypass control system are adequate for the EPU conditions. To ensure an acceptable operating margin exists, the licensee will perform specific PCS tests during the power ascension phase. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.2.2 EHC Turbine Control System

The licensee reviewed the T/G EHC system for the increase in core thermal power and the associated increase in rated steam flow. The licensee concluded that new TCV DFG tuning and an updating of the characteristic TCV tuning parameter curve are necessary for the control systems to perform normally at the EPU conditions. The licensee stated that the control systems are expected to perform normally for EPU RTP operation. This conclusion is consistent with ELTR1 and, therefore, is acceptable.

The licensee further concluded that no modifications to the turbine control valves or the turbine bypass valves are required for operation at the EPU throttle conditions. Normal manual operator controls will be used in conjunction with the associated operating procedures. The licensee will perform confirmation testing during the initial power ascension. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.2.3 Feedwater Control System

The Feedwater Control System (FWCS) controls reactor water level during normal operations. The licensee evaluated the capacity of the feedwater pumps and concluded the capacity is adequate to support EPU RTP operation. The basic capacity requirement for adequate reactor water level control is approximately 105% of the operating point flow rate. The licensee stated that the control signal range is capable of accessing as much of the flow as needed and, therefore, the capacity is sufficient for acceptable control. This conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

The licensee stated that the FWCS is adjusted to provide acceptable operating response on the basis of unit behavior. The existing control system has been set up successfully to cover the current power range using startup and periodic testing. The licensee further stated that the operating water level or water level trip setpoints required for the EPU will not be changed from the existing setpoints. For the EPU, the FWCS device settings have sufficient adjustment ranges to ensure satisfactory operation. However, the feedwater flow transmitters and associated components will be re-calibrated for proper operation at EPU conditions. This will be confirmed by the licensee by performing unit tests during the power ascension to the EPU conditions. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.2.4 Leak Detection System

The licensee evaluated the instrument setpoints associated with the leak detection system with respect to the slightly higher EPU operating steam flow and feedwater temperature. Each of the systems, where leak detection potentially could be affected by the EPU, is addressed below.

Main Steam Line Temperature-Based Leak Detection: The increased feedwater temperature resulting from the EPU affects the main steam leak detection system. However, the licensee concluded maintaining the existing AL and associated isolation value is conservative with respect to leak detection. The NRC staff finds that maintaining the existing setpoint while operating at a higher steam flow and a higher feedwater temperature is conservative and, therefore, is acceptable.

RWCU System Temperature-Based Leak Detection: The licensee stated that there is no increase in the RWCU system temperature or pressure due to the EPU. Therefore, the licensee concluded, there is no effect on the RWCU temperature-based leak detection. This conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

RCIC System Temperature-Based Leak Detection: The licensee stated that the operating reactor dome pressure and temperature in the EPU will not be increased. Therefore, the licensee concluded, there is no change to the RCIC system temperature or pressure, and thus, the RCIC temperature-based leak detection system is not affected. This conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

HPCI System Temperature-Based Leak Detection: The licensee stated that operating reactor dome pressure and temperature in the EPU will not be increased. Therefore, the licensee concluded, there is no change to the HPCI system temperature or pressure, and thus, the HPCI temperature-based leak detection system is not affected. This conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

Non-Temperature-Based Leak Detection: The licensee stated that the non-temperature-based leak detection systems are not affected by the EPU. The NRC staff agrees with this conclusion, and finds this acceptable.

5.3 Instrumentation Setpoint Evaluation

The determination of instrument setpoints is based on plant operating experience, conservative licensing analyses, and/or (limiting) design/operating values. The licensee established the instrument setpoints in the TS using accepted setpoint methodologies. The licensee selected each setpoint with sufficient margin between the actual trip setting and the value in the safety analysis (AL) to allow for instrument accuracy, calibration, and drift.

ELTR1 discusses those instrument setpoint ALs that are potentially affected by the EPU. Plant setpoints derived from the EPU ALs provided in ELTR1 ensure timely actuation of the necessary safety functions while avoiding spurious trips wherever possible during EPU operation. As stated in ELTR1, if an AL does not change, then no change in its associated plant setpoints [i.e., AV and nominal trip setpoint (NTSP)] is required for an EPU. The licensee concluded that changes in the setpoint margins on the basis of potential changes in instrument accuracy and calibration errors caused by the small change in environmental conditions around the instrument due to the EPU are expected to be negligible. This conclusion is consistent with the guidance provided in ELTR1, and the NRC staff finds it acceptable.

The NRC staff evaluated the following licensee setpoint-related evaluations on the basis of the generic guidelines in ELTR1.

5.3.1 High-Pressure Scram

During a pressure increase transient that is not terminated by a direct or a high flux scram, the high-pressure scram terminates the event. Because no pressure increase is associated with this EPU, the licensee concluded that the scram AL on reactor high-pressure should remain unchanged. This conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.2 High-Pressure Recirculation Pump Trip

The Anticipated Transient Without Scram (ATWS) recirculation pump trip (ATWS-RPT) trips the pumps during plant transients associated with increases in reactor vessel dome pressure and/or low reactor water level, LL2/L2. The ATWS-RPT is designed to provide negative reactivity by reducing core flow during the initial part of an ATWS. The ATWS-RPT high-pressure setpoint is a significant factor in the analysis of the peak reactor vessel pressure from an ATWS event. The low reactor water level ATWS-RPT is not a significant factor for the limiting ATWS events.

The major consideration for the high-pressure ATWS-RPT is an increase in the calculated peak vessel pressure during a hypothetical ATWS event, because of the higher initial power. The current high-pressure ATWS-RPT TS AV is used in the licensee's EPU ATWS evaluation. This evaluation concluded that the calculated peak vessel pressure remains below its allowable limit for the limiting ATWS event. Therefore, the NRC staff concludes that the current high-pressure ATWS-RPT TS AV is acceptable for the EPU.

5.3.3 Safety Relief Valve

Because there is no increase in reactor operating dome pressure, the SRV AL for setpoints do not need to be updated. The licensee used the current values in the overpressure protection and transient analyses discussed in the licensee EPU submittal. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.4 Main Steam High Flow Isolation

The AL for the EPU remains at 140% of rated steam flow. The licensee will recalibrate the instrumentation for the higher steam flow condition. This calibration will ensure that a sufficient difference to the trip setpoint exists to allow for normal plant testing of the MSIVs and turbine stop and control valves while still providing adequate protection for the main steam line break accident. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.5 Neutron Monitoring System

The licensee will maintain the MELLLA domain thermal power slope of the APRM flow-biased scram AL line in terms of absolute core power versus recirculation drive flow for the EPU. The licensee stated that this simulated thermal power (STP) scram slope, in terms of relative core power and recirculation drive flow at the EPU condition, is obtained by applying the ratio of the OLTP to the EPU level to the slope portion of the flow-biased scram equation. The APRM flow-biased scram AL intercept is adjusted to match the associated clamped AL at the minimum operating core flow (approximating the recirculation drive flow) corresponding to the new RTP. In effect, the APRM flow-biased setpoint rescaling maintains comparable margin between the operating region and the APRM trips. There is no significant effect on the instrument errors or uncertainties; therefore, the AV is established by directly incorporating the relative change in the AL only. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

As described above, the licensee will revise the AL for the flow-biased portion of the APRM STP scram for TLO. The fixed portion (clamp) of the APRM STP scram that is based on the percent power value from the flow-biased equation at the minimum required core flow at 100% power point will not be changed. The AL for the fixed portion (clamp) of the APRM STP scram is the same as that for TLO and remains the same in terms of percent of the rated power for the EPU conditions. Therefore, the AV of the APRM STP scram remains unchanged. However, the AL for the flow-biased portion of the APRM STP scram is revised (see TS changes in Section 3.4). This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

Because the RBM power and trip ALs remain unchanged, the AVs of the RBM power and trip setpoints will not be changed. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.6 Main Steam Line High Radiation Isolation

The licensee stated that the main steam line normal radiation level increases approximately proportionally to power. The setpoint AL for condenser vacuum pump trip is based on the source radiation from a postulated control rod drop accident (CRDA). Implementation of the EPU does not affect the setpoint AL. No change in the TS is required. The setpoint will be adjusted accordingly to account for the increase in normal radiation levels. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.7 Low Steam Line Pressure MSIV Closure (RUN Mode)

The purpose of this setpoint is to initiate MSIV closure on low steam line pressure when the reactor is in the RUN mode. The licensee stated that this setpoint will not be changed for the EPU. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.8 Reactor Water Level Instruments

The licensee stated that the reactor water level ALs used in the safety analyses and their associated AVs will not be changed as a result of the EPU. For example, the reactor low water level scram (LL1/L3) AL will remain the same as the LL1/L3 AL prior to the EPU. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.9 Main Steam Line High Temperature Isolations

The licensee stated that the normal operating ambient temperature in the MSIV pit area is expected to increase <2°F after the EPU. Use of the existing ALs for detecting high ambient temperature in these areas is conservative with respect to leak detection, and thus, the ALs will not be changed. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

The licensee stated that although Section F.4.2.8 of ELTR1 states that the associated normal trip setpoint may require an associated increase, the minimal temperature increase in the BSEP units will not necessitate such an increase. This conclusion is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.10 Low Condenser Vacuum MSIV Trip

The BSEP plants have a low condenser vacuum MSIV isolation trip. The lower low condenser vacuum MSIV isolation setpoint is established to eliminate a possible release pathway during a loss of condenser vacuum event. The low condenser vacuum MSIV isolation upper setpoint is established at a level below the turbine trip setting to minimize the subsequent pressurization transient associated with the termination of steam flow from the reactor to the condenser due to the loss of condenser vacuum. The licensee stated that, to produce more electrical power, the amount of heat discharged to the main condenser will be increased by approximately 17%. This added heat load will reduce slightly the level of vacuum within the condenser. For the EPU, the licensee will not change the turbine stop valve (TSV) and bypass valve trip setpoints, and therefore, the existing low condenser vacuum MSIV isolation trip will not be changed. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.11 TSV Closure and Turbine Control Valve (TCV) Fast Closure Scram Bypass

The TSV closure and TCV fast closure scram bypass trip allows these scrams to be bypassed, when reactor power is sufficiently low, such that the scram function is not needed to mitigate a T/G trip. This power level is the AL for determining the actual trip setpoint, based on the turbine first stage pressure (TFSP). The licensee stated the TFSP setpoint will be chosen to allow operational margin so that anticipatory scrams from TSV closure and TCV fast closure can be avoided, by transferring steam to the turbine bypass system during T/G trips at low power. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

The licensee stated that the methodology in the ELTR1 is the same methodology used for the initial establishment of the TFSP setpoint and will not be changed for the EPU. On the basis of the guidelines in ELTR1, the TSV Closure and TCV Fast Closure Scram Bypass AL will be reduced by the ratio of the power increase. The new AL will not be changed with respect to absolute thermal power and steam flow. Because the setpoint will not be changed in terms of absolute power, the licensee concluded that there is no effect on the transient response. Consequently, the same steam flow values will be maintained for plant startup. Although the AL TFSP trip value in absolute thermal power does not change, its corresponding pressure value may need to be changed due to the high-pressure turbine modification for EPU. Until the new TFSP trip value is established, the licensee will use procedural restrictions to ensure that the initial TFSP trip value will not be exceeded without the TSV Closure and TCV Fast Closure Scrams enabled. The EPU TFSP trip value will be determined during initial EPU startup testing. The NRC staff finds the retention of the TFSP setpoint in terms of absolute power and changing the corresponding pressure value to accommodate the high-pressure turbine modification during initial EPU startup testing is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.12 Rod Worth Minimizer

The Rod Worth Minimizer (RWM) AL is based on total steam flow as a measure of reactor power. The function of the RWM is to support the operator by enforcing rod patterns until reactor power has increased to a minimum power level. Above the minimum power level, sufficient negative reactivity feedback mechanisms exist to limit the severity of a worst-case CRDA. The licensee proposed to rescale the minimum power level RWM AL in percent rated power proportional to the power increase (from 10% RTP to 8.75% EPU RTP). This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.13 Pressure Regulator

The PCS is discussed in Section 5.2.1, above. The pressure regulator setpoint, pressure regulator gain, main steam line pressure drop, TSV inlet pressure, and T/G-required load setpoint are related to each other and to reactor dome pressure. The licensee stated that the reactor dome pressure will remain the same for the EPU. However, the increased steam flow will result in a slightly greater steam line pressure loss. Therefore, the licensee will adjust the pressure regulator setpoint to achieve the desired turbine inlet operating conditions. The licensee will reconfirm the small differences in tuning parameter values during the power ascension testing for each pressure regulator. Additionally, the licensee will perform specific EHC and pressure regulation system tests during the initial EPU ascension phase, as summarized in Section 10.4 of the licensee's submittal. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.14 Feedwater Flow Setpoint for Recirculation Cavitation Protection

The licensee stated that the current value of the feedwater flow setpoint will remain unchanged in terms of actual feedwater flow rate, because the cavitation interlock requirement is not based on the percentage of rated flow. However, the licensee continued, the relative setpoint, as it appears on the power/flow map, will be reduced slightly to account for the EPU RTP. This approach is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.15 RCIC Steam Line High Flow Isolation

The licensee stated that the AL setpoints for the RCIC steam line high flow isolation will continue to be maintained on the basis of 300% of maximum rated steam flow to the RCIC turbine. Because the EPU does not include an increase in reactor operating pressure, the high flow differential pressure values reflecting the RCIC turbine steam flow rate will remain the same as for the pre-EPU. Maintenance of the ALs for the RCIC steam line high flow isolation trip at the existing AL is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.3.16 HPCI Steam Line High Flow Isolation

The licensee stated that the ALs for the HPCI steam line high flow isolation trip will continue to be maintained on the basis of 300% of maximum rated steam flow to the HPCI turbine. Because the EPU does not include an increase in reactor operating pressure or a change in SRV setpoints, the high flow differential pressure values reflecting the maximum HPCI turbine steam flow rate will not change from the pre-EPU values. Maintenance of the AL for the HPCI steam line high flow isolation trip at the existing AL is consistent with the guidance provided in ELTR1 and, therefore, is acceptable.

5.4 Conclusion

Based on the above review and justifications for TS changes and plant modifications, the NRC staff concludes that the licensee acceptably addressed the effect of the EPU on the NSSS monitoring and control systems, the BOP monitoring and control systems, and instrument AVs in the TS. Additionally, the NRC staff finds that the proposed TS changes and TS Bases changes are acceptable.

6.0 ELECTRICAL POWER AND AUXILIARY SYSTEMS

6.1 Alternating Current (AC) Power

6.1.1 Background

The licensee's power system includes the generators, the main transformers, the switchyard, the unit auxiliary transformers and the startup transformers. The generator for each unit is rated at 24 kV, 963 MVA, 0.96 pf. The generator is hydrogen cooled. Each generator is connected through a forced cooled isolated phase bus to a bank of three single-phase main transformers that step up the generator voltage from 24 kV to 230 kV. The unit auxiliary transformers are also connected directly to the isolated phase bus (rated at 25,000 amperes), which connects the generator to the main power transformers. A manual no-load break disconnect switch, located between the generator and the potential transformer taps, provides isolation of the generator from the main and unit auxiliary transformers. When opened, this disconnect switch allows the main and unit auxiliary transformers to be used as a delayed second source of offsite power. Transmission for the plant consists of eight 230 kV lines, four lines for each unit. The transmission lines and the electrical distribution system were evaluated to conform to GDC 17 of Appendix A to 10 CFR 50. Because the licensee performed its evaluation against the standards of GDC-17, the staff also used GDC-17 to evaluate the acceptability of the application.

The change in electrical demand because of this power uprate is associated with load increases for recirculation pumps, condensate pumps, main transformer controls/cooling equipment, isolated-phase bus cooling equipment, and a new condensate cooling system. The condensate, condensate booster and stator water cooling pumps require larger motors due to increased flow during EPU conditions. Loads for main transformer controls/cooling equipment and isolated-phase bus cooling equipment increase due to increased cooling requirements. The licensee revised the electrical system calculations to address the load increases. Based on these revised calculations, the existing load shedding scheme actuated upon a LOCA event is expanded to also actuate during generator trip events (non-LOCA). This provides additional protection against inadequate voltages on the emergency buses during potential degraded grid events.

6.1.2 Grid Stability

The licensee has evaluated the grid stability analysis for the EPU and determined that CP&L needs to implement several modifications and procedure changes to ensure grid stability. The licensee has proposed to install an Out-of-Step protective scheme before exceeding CRTP. The operation of an Out-of-Step scheme is based on the fact that there is a progressive change in impedance as viewed by the relay units and not an instantaneous change as would occur during a fault. Experience has indicated a severe disturbance can cause system instability and result in a loss of synchronism between different generating units on an interconnected system. Such instability is termed an Out-of-Step condition. Since a prolonged Out-of-Step condition can result in a complete system shutdown, it is desirable to detect this condition as soon as possible and take the appropriate action. The Out-of-Step protective scheme will provide tripping of the main generator on a loss of synchronism. This protective trip is designed to prevent damage to the generator and to preserve grid stability by expeditiously tripping the unstable unit. The protective scheme will also block out-of-step induced tripping of the transmission lines terminating to the unit's switchyard. This ensures continuity of offsite power. The licensee has also proposed to install power system stabilizers (PSS) on Unit 1 before exceeding 111% ORTP, and on Unit 2 before exceeding CRTP to provide adequate damping of post-transient oscillations. In addition, during key line outages, the licensee will establish procedural controls for limiting generator output before exceeding CRTP to maintain adequate damping of oscillations. The NRC staff was concerned about the damping of the post-transient oscillations of the PSS and asked the licensee as to how much reactive power (MVARS) is being provided by the PSS. By letter dated December 17, 2001, the licensee stated that the PSS is a supplementary control that is input to the excitation system to provide damping to power system oscillations. The inputs are those signals in which the oscillations are observable, such as speed (i.e., frequency) and power. The PSS input has the appropriate phase compensation to modulate generator field voltage such that torques are generated that are out of phase with those causing the power oscillations. The PSS acts to dampen out these oscillations in both normal and contingency conditions. The exact value of pre-and post- disturbance damping, with and without PSS, will depend on the electrical system conditions, operating point, and type of disturbance. The primary purpose of the PSS is to add damping to the power-angle (i.e., speed) oscillations by modulating the voltage regulator input. The PSS control is not designed to change voltage/MVAR output in a significant fashion. The PSS modification provides a positive contribution to damping of the generator rotor angle swings, which are in a broad range of frequencies in the power system. The low frequency modes are due to coherent groups of generators swinging against other groups in the interconnected system. Weak ties due to line outages and heavy system loads can lead to poorly damped inter-tie modes. The PSS control provides significant improvements in inter-tie mode damping with the application of a stabilizer. The PSS also provides damping for the local mode, with the generator swinging against the rest of the power system. Stronger system ties and lighter loading tend to give higher local mode frequencies, and weaker ties and heavier loading tend to give lower local mode frequencies. The PSS performance is designed to give enhanced performance over a wide range of system conditions, which may result from different operating conditions such as lines out-of-service and varying load levels. The PSS has protective limiters to keep the generator operating within operating limits.

On the basis of this information, the NRC staff determined that through replacement of the main power transformer, the installation of stabilizers to damp the oscillations, and the installation of Out-of-Step protective relays, grid stability at BSEP will be maintained. Therefore, the NRC staff has reasonable assurance that GDC-17 will be met at the EPU condition.

6.1.3 Main Generator

The main generator is currently rated at 924 MWe at 0.96 power factor (pf). At the extended uprated thermal rating of 2923 MWt, the main generator gross output will be 1006 MWe at 0.968 pf. Modifications supporting the initial power uprate include rewinding of the main generator for Unit 1. Rewinding of the main generator for Unit 2 was completed during the Spring 2001 refueling outage. The existing main generator and main transformer protective relaying scheme will require minor modifications to ensure reliable operation before achieving full EPU. The licensee has proposed to install Out-of-Step protective relays before exceeding current licensed thermal power to protect the main generator. The licensee has also proposed additional generator lockout load shed modifications to assure adequate voltage support due to a loss of coolant accident (LOCA) following a generator trip before the EPU is implemented. The NRC staff was concerned about the main generator lockout load shed modification and asked the licensee to provide details of the modification, including the loads which will be shed upon a generator lockout. By letter dated December 17, 2001, the licensee responded that the projected future load growth on the grid in the area will make it more difficult for the grid to maintain the minimum required switchyard voltage during a LOCA and/or unit trip. This minimum required voltage is based on the minimum emergency bus recovery voltage required to reset the degraded grid voltage relays (DGVR) following motor starts. To ensure that the DGVRs have adequate reset voltage, both Unit 1 and Unit 2 are currently equipped with selective load shedding, which occurs on receipt of a LOCA signal for the associated unit. This load shed scheme is progressive in nature in that, initially, only a few large 4 kV BOP motors are shed. Additional loads may be selected for shedding as future grid load increases. EPU compounds this issue by adding considerable load to each unit's AC electrical distribution system. The objective of the main generator lockout load shed modification is two-fold: (1) to ensure that adequate capacity, voltage, and short circuit margins are maintained for the ac electrical distribution system post-EPU, and (2) to ensure adequate long-term 230 kV switchyard LOCA voltage support. To accomplish these objectives, the following changes will be implemented by this modification for each unit:

- The existing administrative load management limit of 3315 amps (i.e., pre-LOCA) will be increased to 3550 amps.

- The setpoints of the overcurrent relays associated with the BOP bus 1C(2C) and BOP bus 1D(2D) incoming line breakers will be increased.

- The breaker control circuits for the majority of non-safety related 4 kV motors will be modified to provide the capability to selectively trip the load breaker on a generator lockout signal. Selection of loads for tripping will be procedurally controlled.

- Procedure changes will be implemented to provide tripping of two running heater drain pump motors upon a generator lockout signal.

- Procedure changes will be implemented to block automatic starting of the standby condensate pump (CP) and standby condensate booster pump (CBP) motors upon a generator lockout signal.

- Procedure changes will be implemented to block automatic starting of the standby CP and standby CBP motors upon a LOCA signal.

- Procedure changes will be implemented to provide tripping of one running circulating water intake pump (CWIP) motor upon a LOCA signal.

- Procedure changes will be implemented to provide "part-time" tripping of one running CWIP motor on a generator lockout signal during high grid load conditions.

The generator lockout load shed signal will be derived from three generator lockout relays (i.e., 86G2, 86GP2, and 86GB2). A spare "normally open" contact on each relay will be placed in parallel and the resultant signal multiplied and supplied to the breaker trip circuits of the affected 4 kV motors supplied from the 1C(2C) and 1D(2D) buses. A key-lock selector switch will be installed on the front face of the 4.16 kV switchgear motor compartments. The switch will have two possible states labeled "Enable" and "Disable." With the switch in the "Enable" position, receipt of a generator lockout signal will trip the associated load or prevent the load from starting. When the switch is in the "Disable" position, the load will not trip or be prevented from startup with a generator lockout signal present. Switch positions will be procedurally controlled.

Operating procedure changes will implement "part-time" tripping of a second running CWIP motor on a unit trip signal during periods of abnormally high grid load conditions. DTRM-GP-24 of the DTRM requires the dispatcher to inform the affected unit's control room operator when the Eastern Transmission Area load is approaching the point where the required post-unit trip minimum switchyard voltage can no longer be sustained. When it has been determined that the Eastern Transmission Area can no longer support the required LOCA post-unit trip minimum switchyard voltage, a second notification will be made. Prior to the second notification, Operators will refer to plant procedure 1(2)-OP-50, "Unit Trip Load Shedding of Selected Loads." This will guide them to enable the unit trip load shed feature for the second running CWIP on a "part-time" basis. Tripping this load on a unit trip will maintain adequate voltages at the 4.16 kV emergency buses. Upon dispatcher notification that the grid has returned to normal load conditions, the unit trip load shed switch for this load will be procedurally returned to the "Disable" position. The main generator lockout load shed modification also installs the hardware capability to provide additional "part-time" load shedding; procedural changes to provide any additional load shedding will be invoked by future design change packages, as needed. To eliminate the potential for inadvertent tripping of the incoming line breakers to BOP buses 1C(2C) and 1D(2D) due to automatic starting of loads to support an opposite unit's LOCA, this modification will increase the overcurrent relay setpoints associated with the bus 1C(2C) and bus 1D(2D) incoming line breakers.

The NRC staff’s review determined that by rewinding the main generator, modifying the generator and main transformer protective relaying scheme, and implementing the load shed modifications, the main generator can be operated safely at the EPU condition.

6.1.4 Main Power Transformers

The main power transformer bank consists of three single-phase units, each rated at 320 MVA for a total capacity of 960 MVA. The main power transformers for both units can continuously carry the maximum generator output up to 115% ORTP. However, the licensee has proposed to replace the existing main power transformers before exceeding 115% original licensed thermal power. The replaced main power transformer bank will consist of three single phase units, each rated at 400 MVA for a total capacity of 1200 MVA. As mentioned earlier in Section 3.2, the existing main generator and main power transformer protective relaying scheme will require minor modifications to ensure reliable operation before achieving full EPU. The NRC staff review determined that by replacing the main power transformer and modifying the generator and main transformer protective relaying scheme, the main power transformer can be operated safely at the EPU condition, and is therefore acceptable.

6.1.5 Unit Auxiliary Transformers

The unit auxiliary transformers (UAT) are each three-phase, double secondary rated at 27/36/45 MVA for 55^{o} C temperature rise. The EPU output of X-winding and Y-winding of the UAT are 1,856 amperes and 3,900 amperes respectively. The X-winding and Y-winding of the UAT are rated at 2,000 amperes and 4,000 amperes respectively. The NRC staff's review determined that the loading on the UAT would be adequate at the EPU condition.

6.1.6 Startup Transformers

The startup auxiliary transformers (SATs) are each three-phase, double secondary rated at 27/36/45 MVA for 55^{o} C temperature rise. The EPU output of X-winding and Y-winding of the SAT are 1,856 amperes and 3,900 amperes respectively. The X-winding and Y-winding of the SAT are rated at 2,000 amperes and 4,510 amperes respectively. The NRC staff's review determined that the loading on the SAT would be adequate at the EPU condition.

6.1.7 Isolated Phase Duct

The isolated phase bus conductors and insulators are protected and shielded by continuous, welded aluminum enclosures. The Unit 1 and Unit 2 isolated phase bus cooling will be modified before exceeding the CRTP to handle the additional loads associated with the EPU. The NRC staff's review determined that with better cooling, the isolated phase duct can be operated safely to accept the maximum generator output at the EPU condition.

6.1.8 Emergency Diesel Generators

Power required to perform safety-related functions (pump and valve loads) is not increased with the EPU, and the current emergency power system remains adequate. The systems have sufficient capacity to support all required loads for a safe shutdown, to maintain a safe shutdown condition, and to operate the engineered safety feature equipment following postulated accidents. The NRC staff's review determined that the EPU does not affect the loading on the emergency diesel generator.

6.1.9 Conclusions

The NRC staff has evaluated the effect of EPU on the necessary plant electrical power systems, grid stability, the station blackout (SBO) coping capability, and the environmental qualification of electrical equipment. Results of these evaluations show that with the modifications for the extended power uprate, the plant would meet the requirements of GDC 17, 10 CFR 50.63, and 10 CFR 50.49, and the proposed power uprate is, therefore, acceptable.

6.2 Direct Current (DC) Power

The DC loading requirements were reviewed, and no reactor power-dependent loads were identified. Based on the information submitted, the NRC staff finds that operation at the EPU condition does not increase dc loads beyond nameplate rating, and this is acceptable.

6.3 Fuel Pool

6.3.1 Fuel Pool Cooling

The Fuel Pool Cooling and Cleanup (FPCC) System is designed to remove the decay heat from the spent fuel assemblies stored in the SFP, and to clarify and purify the water in the SFP. The SFPCC system consists of two independent SFP cooling trains each primarily equipped with one pump[2], one heat exchanger, and its associated valves, piping, instrumentation and controls. Heat is removed from the SFP heat exchanger by the reactor building closed cooling water system which, in turn, rejects the heat to the service water system. In addition, the RHR serves as a back-up system to the FPCC system and provides supplemental cooling to maintain the SFP below the temperature limit of 150°F in the event that the SFP heat load exceeds the heat removal capability of the FPCC cooling system.

Also, BSEP is designed with a temporary supplemental spent fuel pool cooling (SSFPC) system that can be used as an alternate to the RHR system fuel pool cooling assist mode and shared between Unit 1 and Unit 2. The SSFPC system is divided into primary and secondary cooling loops. The primary cooling loop removes heat from the SFP and rejects it to the secondary cooling loop.

The primary cooling loop has a combination of permanently installed piping and temporarily installed equipment. The temporarily installed equipment, which consists of two pumps, two heat exchangers, and their associated valves, piping, instrumentation and controls, is powered from the safety-related emergency buses. The secondary cooling loop also has a combination of permanently installed piping and temporarily installed equipment. The temporarily installed equipment for the secondary cooling loop consists of two pumps, two cooling towers, and their associated valves, piping, instrumentation and controls. It is powered from non-safety-related offsite power back-up by a temporary diesel generator.

The design of the SSFPC system is such that it functions independently of the FPCC system. When the SSFPC system is in service, the fuel pool cooling assist mode of the RHR system can be removed from service. However, the operation of this shared SSFPC system is limited to decay heat removal from one SFP at a time during outages. In the response, dated December 10, 2001, to the NRC staff's RAI, the licensee stated that installation, initial startup, operation, removal of the SSFPC system, and equipment maintenance and storage are controlled via plant procedures.

The following are the criteria established in Section 9.1.2.3.2.3 of the UFSAR for SFP cooling during all scenarios of core offload outages:

1. The SFP cooling system alone shall maintain the SFP bulk temperature at or below 150°F following a partial core unload.

2. The SFP cooling system operated in conjunction with the RHR system or the SSFPC system shall maintain the SFP bulk temperature at or below 150°F following a full core unload.

The licensee performed evaluations that demonstrate that the combination of the FPCC system heat exchangers and the RHR system in the fuel pool cooling assist mode (or SSFPC system) is sufficient to remove the maximum SFP heat load resulting from plant operations at the proposed EPU level during a planned refueling outage or an unplanned (abnormal) full-core offload event.

In the response to the above-cited RAI, the licensee stated that under a partial core offload

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[2] The SFP cooling pumps are connected in parallel, as are the two heat exchangers.

refueling condition, the maximum SFP heat load is 14.1 x 10^6 Btu/hr when the offload is started at 190 hours after shutdown. With only the FPCC system operating and a service water temperature of 95°F, the SFP temperature will be at or below 149.9°F. Under abnormal (full core offload) heat load conditions, the maximum SFP heat load is 35.5 x 10^6 Btu/hr at 24 hours after shutdown. With both the FPCC system and RHR system operating, and a service water temperature of 95°F, the SFP temperature will be at or below 147°F. In any event, the SFP temperature under a planned refueling outage or an unplanned full-core offload does not exceed the SFP temperature limit of 150°F.

The heat removal capability of the SFP cooling system is dependent on the service water temperature, which varies throughout the year, and the decay heat load. Decay heat load is a function of the fuel assemblies in the SFP, the number of fuel assemblies to be transferred to the SFP from the reactor vessel, the transfer rate, the time of the start of the transfer, and the decay time after shutdown. For actual shutdowns, fuel offload can start prior to 190 hours but not prior to 24 hours[3] following shutdown, and the SFP water temperature still can be maintained below 150°F. Therefore, prior to a planned or unplanned outages, the licensee will perform a cycle-specific analysis per plant procedure 0AP-022, “BNP Outage Risk Management,” to determine the fuel assemblies' in-reactor vessel decay time for core offload based on the actual service water temperature. Plant procedure 0AP-022 also requires, as a minimum, a primary and backup means of decay heat removal to be available. Each system must be capable of maintaining the SFP temperature at or below 150°F under the worst anticipated heat load.

In addition, plant operating procedures require that the SFP temperatures be monitored at least once per shift and that the SFP temperatures be monitored hourly when the SSFPC system is in service. In the event of a loss of SFP cooling or when the SFP temperature reaches 125 °F during a refueling outage or core offload, plant procedure 0AOP-38.0, “Loss of Fuel Pool Cooling and Cleanup,” directs appropriate actions to be taken. Appropriate actions include placing the SSFPC system in service or aligning the RHR system to provide supplemental cooling and restore the systems to operations. This will provide additional assurance that the above SFP temperature limit of 150°F during planned refueling outages or unplanned full-core offloads is not exceeded.

Based on the review of the licensee's rationale and evaluations, the NRC staff finds find that plant operations at the proposed EPU level do not change the design aspects and operations of the SFP cooling system and the RHR system in the fuel pool cooling assist mode or SSFPC system, and therefore, are acceptable.

6.3.2 Crud Activity and Corrosion Products

The licensee stated that crud activity and corrosion products associated with fuel can increase very slightly due to the EPU. The increase is insignificant, and SFP water quality is maintained by the fuel pool cooling and cleanup system. The NRC staff finds this acceptable.

6.3.3 Radiation Levels

The licensee stated that radiation levels around the SFP may increase slightly mainly during fuel handling operations. The increase does not significantly increase the operational doses to personnel or equipment. The NRC staff finds this acceptable.

6.3.4 Fuel Racks

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[3] The fuel assemblies in-reactor vessel decay time of 24 hours was assumed in the analysis of radioactive releases resulting from a fuel handling accident.

The licensee stated that the spent fuel racks are designed for higher temperatures than are anticipated from the EPU. There is no effect on the design of the spent fuel racks, because the SFP design temperature is not exceeded. The NRC staff finds this acceptable.

6.4 Water Systems

6.4.1 Service Water Systems

The service water systems are designed to provide cooling water to various systems (both safety-related and non-safety-related systems). All heat removed by these systems is rejected to the ultimate heat sink (UHS).

6.4.1.1 Safety-Related Loads

Safety-related loads include loads from the emergency equipment service water (EESW) system and the residual heat removal service water (RHRSW) system.

6.4.1.1.1 Emergency Equipment Service Water System

The EESW system provides cooling water to the following essential components/systems following a LOCA: RHR pump seal cooling heat exchangers, fan cooling units for RHR and core spray pump rooms, and emergency diesel generator coolers.

The licensee performed evaluations and stated that the performance of the EESW system during and following a LOCA is not dependent upon the point of rated reactor thermal power operation up to the EPU RTP. The diesel generator heat loads and RHR system flows remain unchanged for LOCA conditions following EPU operations. The building cooling loads also remain the same because equipment performance in these areas remains essentially unchanged for post LOCA conditions. Therefore, plant operations at the proposed EPU level do not require the modification of the EESW system for the safety-related loads.

Based on the review of the licensee's evaluation and rationale, the NRC staff finds that BSEP operations at the proposed EPU level do not change the design aspects and operations of the EESW system, and have an insignificant or no impact on the EESW system. Therefore, the NRC staff concludes that the EESW system at BSEP remains adequate for plant operations at the proposed EPU level to perform its safety function during and following a LOCA.

6.4.1.1.2 Residual Heat Removal Service Water System

The residual heat removal service water (RHRSW) system provides cooling water to the RHR heat exchangers[4] under normal or post-accident conditions. The licensee performed containment pressure and temperature response analyses, which demonstrate that the capability of the containment system is adequate for plant operations at the proposed EPU level. In the containment pressure and temperature response analyses, the post-LOCA RHRSW flow rate and temperature were assumed to be unchanged for EPU conditions. Therefore, the

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[4] The long-term containment pressure and temperature responses following a LOCA are governed by the ability of the RHR system to remove the decay heat from the suppression pool.

RHRSW system remains adequate for plant operations at the proposed EPU level to perform its safety function during and following a LOCA. The NRC staff's evaluation of the containment system performance for plant operations at the proposed EPU level is addressed in Section 4.1.

During shutdown cooling with the RHR system, heat loads on the RHR heat exchangers will increase proportionally to the increase in reactor operating power level, thus increasing the time required to reach the shutdown temperature. The licensee stated that this has no effect on plant safety. The NRC staff's evaluation of the effect of plant operations at the proposed EPU level on shutdown cooling with the RHR system is addressed in Section 3.9.1.

Based on the review of the licensee's rationale and the evaluation described above, the NRC staff finds that the RHRSW system is acceptable for BSEP operations at the proposed EPU level.

6.4.1.2 Non-Safety-Related Loads

Non-safety-related heat loads include heat loads from the reactor building closed cooling water (RBCCW) system and the turbine building closed cooling water system (TBCCW). Evaluations of the RBCCW system and TBCCW system are addressed in Section 6.4.3 and Section 6.4.4, respectively.

6.4.2 Main Condenser and Circulating Water System

The main condenser and circulating water systems are designed to remove the heat rejected to the condenser, thereby maintaining low condenser pressure as recommended by the turbine vendor. The licensee stated that the performance of the main condenser and circulating water systems was evaluated and found adequate for plant operations at the proposed EPU level.

Since the main condenser and circulating water systems do not perform any safety-related function, the impact of the proposed EPU operations on the designs and performances of these systems was not reviewed.

6.4.2.1 Discharge Limits

The proposed EPU is expected to result in an increase in the temperature of the water discharged to the Atlantic Ocean, which would result in an increase in the size of the thermal plume in the Atlantic Ocean. CP&L addressed this issue in its Environmental Report and made an application to the North Carolina Department of Environment and Natural Resources to revise the National Pollutant Discharge Elimination System Permit for BSEP. The environmental impact is addressed in the Environmental Assessment issued as a separate document by the NRC.

6.4.3 Reactor Building Closed Cooling Water System

The RBCCW system is designed to remove heat from various auxiliary plant equipment housed in the reactor building. The heat loads on the RBCCW system are not increased significantly by the EPU because they depend mainly on either vessel temperatures or flow rates in systems cooled by the RBCCW system. The changes in these vessel temperatures or flow rates are minimal. The licensee performed evaluations and stated that the increase in heat loads on this system due to EPU operations is insignificant, and that this system has sufficient cooling capacity for plant operations at the proposed EPU level.

Although the RBCCW system does not perform any safety-related function, the NRC staff evaluated the impact of plant operations at the proposed EPU on the design and performance of these systems and found it to be insignificant.

6.4.4 Turbine Building Closed Cooling Water System

The TBCCW system supplies cooling water to auxiliary plant equipment in the turbine building. The licensee stated that the TBCCW system heat load increases due to the EPU are those related to the operation of the turbine-generator; however, the TBCCW system has adequate heat removal capability for plant operations at the proposed EPU level.
Although the TBCCW system does not perform any safety-related function, the NRC staff evaluated the impact of plant operations at the proposed uprate power level on the design and performance of these systems and found it to be insignificant.

6.4.5 Ultimate Heat Sink

The UHS intake is the Cape Fear River and the discharge is the Atlantic Ocean. The licensee performed an evaluation and stated that as a result of plant operations at the proposed EPU level, the post-LOCA UHS water temperature does not change. The UHS continues to provide sufficient cooling water at a temperature of less than 92^{0}F (design temperature) to remove the increased heat loads following a DBA.

Based on the review of the licensee’s rationale and the experience gained from its review of power uprate applications for similar BWR plants, the NRC staff finds the licensee's conclusion that plant operations at the proposed EPU level will have no impact on the UHS acceptable.

6.5 <u>Standby Liquid Control System</u>

The licensee evaluated the SLC system injection and shutdown capability for the EPU operation. For BSEP Units 1 and 2, the SLC system is a manually operated system that pumps concentrated sodium pentaborate solution into the reactor vessel through the SLC spargers in the lower plenum in order to provide neutron absorption and bring the reactor to a subcritical condition.

The shutdown capability of the SLC system is evaluated at every reload to account for the impact of core design changes on the required boron concentration. The licensee stated that the required cold shutdown boron concentration is driven less by the plant's RTP than the total reactivity requirement to achieve the fuel cycle. The use of a new fuel design, increases in the batch fraction, and changes in the fuel enrichment in combination with the total reactivity required to achieve the fuel cycle operating time affect the required SLC shutdown concentration. The licensee determined that with a single reload batch of GE14 fuel, the current SLC boron concentration is sufficient to bring and maintain the units at cold shutdown conditions. However, to achieve the EPU operation, the core design would require the loading of a second batch of GE14 and the SLC boron required to achieve cold shutdown condition would increase from 660 ppm to 720 ppm.

Therefore, to support Unit 2 Cycle 16 and Unit 1 Cycle 15 SLC shutdown concentration requirements, CP&L plans to submit an amendment by August 30, 2002, for Unit 2, and August 29, 2003, for Unit 1, requesting an increase in the SLC boron concentration for both units from 660 ppm to 720 ppm.

10 CFR 50.62, which sets forth requirements for reducing the risk of an ATWS, requires each BWR to have an SLC system with the capability of injecting into the reactor a borated water solution at such a flow rate, boron concentration, and boron-10 isotope enrichment equivalent to those resulting from injection of 86 gpm of 13 weight percent sodium pentaborate into a 251-inch diameter vessel. ATWS is discussed in Section 9.3.1. The licensee evaluated the SLC system capability to meet the requirements in 10 CFR 50.62. The SLC system is designed to inject at a maximum reactor pressure equal to the upper analytical setpoints for the lowest group of SRVs operating in the relief mode. Since the reactor operating dome pressure and the SRV setpoints will not change, the licensee stated that the current SLC system process parameters are acceptable. The licensee added that the SLC pumps are positive displacement pumps and small changes in the SRVs setpoint would have no effect on the SLC system capability to inject the required flow rate.

Implicit in the PUSAR evaluation of the SLC system for the EPU condition is that the lifting of the lowest group of SRVs at the upper analytical setpoint would be sufficient to reduce and maintain the reactor dome pressure to the lift setpoint of 1164 psig for an ATWS event. However, the SRV rated steam flow capacity for the BSEP units dropped from 87 percent to 71 percent of the rated steam for the EPU condition. In addition, for an ATWS with isolation, the initial power, stored energy and core reactivity would be higher. NRC has issued Information Notice (IN) 2001-13, “Inadequate Standby Liquid Control System Relief Valve Margin,” informing BWR licensees that the calculated dome pressure for a certain ATWS event could potentially be higher than the pressure used to evaluate the SLC system relief valve margin. For the BSEP units, the SLC bypass relief valve would lift at pump discharge pressure of 1450 psig. Therefore, the NRC staff asked the licensee to review IN 2001-13 and verify that for all limiting ATWS events, the SLC system would be able to inject using the calculated dome pressure and the analytically assumed SLC injection time without lifting of the SLC system bypass relief valves.

Using the setpoint of the upper group of the SRVs (plus 3 % tolerance), the elevation head, calculated two pump pressure losses, and the SLC relief valve tolerance, the licensee determined that the available SLC relief margin is 3 psid, out of a required pump pulsation margin of 30 psid. Consequently, the licensee revised the elevation head and the SLC two pump configuration line losses and arrived at a higher SLC relief valve margin of 18 psid. This calculation was based on the TS value of the high setpoint group (1184.5 psig). Due to the low SLC relief valve bypass margin, the NRC staff reviewed the ATWS pressure responses for all of the limiting ATWS events, the revised elevation head, and system losses.

The licensee used the minimum operator response time of 79 seconds after the ATWS recirculation pump trip to determine the SLC injection times for all of the ATWS events. This would be conservative since it would be based on earlier SLC injection, before the dome pressure decreases, and it is earlier than the assumed time in the ATWS analysis. To determine the SLC system losses, the licensee used actual BSEP Unit 2 tests performed on March 1, 2001, using flow rates within the SLC injection flow rate. The original system losses were based on a 1984 GE evaluation. In the revised calculation, the licensee accounted for the higher elevation of the SLC system and the specific gravity of the boron solution. The predicted ATWS dome pressure after the SLC injection times (ATWS-RPT + 79 seconds) varied from 1194 psig to 1184 psig for the different events. Using a predicted dome pressure of 1194 psig, which also corresponds to the analytical operating setpoint of the highest group of SRVs, the licensee determined an SLC relief valve margin of 8 psid for the ATWS. For the non-ATWS events, the licensee used the lower group of the SRVs (1164 psig) and obtained an SLC relief valve margin of 5 psid.

The licensee concluded that although the SLC relief valve margin for both cases is small, all of the above inputs have enough individual conservatism to provide adequate assurance that the SLC will perform as required. Considering the small margin available, the NRC staff reviewed all the corresponding calculations, including the revised values. The NRC staff believes that the ATWS analysis is a best estimate analysis with some conservatism. The licensee's revised calculations have minimal conservatism, except for the maximum operator response time. The NRC staff concludes that the SLC bypass relief valve setpoint margin is small, but acceptable. In an April 29, 2002, letter, the licensee outlined its SLC relief valve margin improvement modifications. CP&L has ordered replacement SLC relief valves that would increase the available margin by 50 psid. The licensee plans to install the replacement valves in the next refueling outages. The NRC staff supports any modifications that would improve the SLC relief valve margin.

The licensee also plans to modify the SLC system in order to increase the boron concentration from 660 ppm to 720 ppm. The August 9, 2001, submittal letter stated that:

> "Transition to the GE14 fuel design is necessary to achieve the full EPU. As a result, modification to the Standby Liquid Control (SLC) system is required to increase the injection capability. Options to support transition to GE14 fuel that were considered included: (1) raising minimum sodium pentaborate solution volume limits for the SLC tank, (2) increasing the boron atomic enrichment to amount required to meet EPU with two pump operation, and (3) increasing the boron atomic enrichment to a higher value to achieve single pump/squib valve success criteria. CP&L has elected to upgrade the SLC system by increasing neutron absorber concentration to a level that enables single SLC pump/squib valve success criteria. When this modification is taken into account, the overall PSA change after the EPU, will be a net 9% reduction in the internal events CDF and a corresponding 28 % reduction in LERF."

The licensee committed to adding two license conditions to the operating licenses in support of this EPU. In a letter dated March 25, 2002, the licensee committed to submit for NRC staff review changes to the SLC system boron concentrations 6 months prior to loading the second batch of GE14 fuel into the BSEP Units 1 and 2 cores. In an April 29, 2002, letter, the licensee also committed to make the changes necessary to support single pump/squib valve shutdown capability. With this SLC modification, one pump/squib valve will be able to inject sufficient boron to shut down the reactor, making the SLC system functionally single-failure proof. Moreover, the single pump/squib valve success criteria would improve the plants' PSA. The NRC staff accepts the licensee's commitment and will review the associated changes in an amendment request 6 months in advance of the implementation schedule. However, CP&L plans to maintain the current two-pump SLC system actuation configuration in order to minimize changes to the current emergency operating procedures (EOPs) and avoid operator retraining.

The NRC staff accepts the licensee's plans because the relief valve margin can be readily improved in other ways.

As discussed in Section 9.3.1, "ATWS Analysis," the licensee reanalyzed the pressure regulator failure to open (PRFO) event based on the limiting unit. The licensee confirmed that the predicted peak reactor vessel pressure when the SLC starts did not increase for the reanalyzed PRFO event. The licensee reanalyzed the event using the limiting Unit 2 turbine bypass capacity. However, the pressure response decreased because the licensee used the actual BSEP SRV tolerance of 34 psid instead of GENE's uncertainty/drift value of 44 psid. Therefore, the SLC system relief valve margin did not decrease for the reanalyzed PRFO event.

Based on the information submitted, the RAI responses and technical justification provided, the NRC staff finds the proposed operation of the SLC system at EPU conditions acceptable.

6.6 Power-Dependent Heating, Ventilation, and Air Conditioning Systems

In a submittal dated August 9, 2001, the licensee provided information as follows for the power-dependent heating ventilation and air conditioning (HVAC) systems:

- The HVAC systems consist mainly of heating, cooling supply, exhaust and recirculation units in the reactor building, drywell, and turbine building.
- EPU operation is expected to result in slightly higher process temperatures and a small increase in the heat load due to higher electrical currents in some motors and cables.
- The areas most affected due to the increase in process temperatures from extraction steam, condensate, feedwater, and/or motor horsepower are the 1A and 1B feedwater heater and condenser area in the turbine building and the areas immediately surrounding the condensate and condensate booster pump motors. Other areas are minimally affected (< 2^0F) by the EPU because the process temperatures remain relatively constant.
- Heat loads in the drywell increase slightly due to increases in the recirculation pump motor horsepower and the feedwater process temperature. The maximum temperature increase in the drywell is 1.8^0F.
- The heat loads discussed above represent an increase of approximately 2% to 5% in the drywell cooling, MSIV valve pit, radwaste building, and main steamline tunnel, and approximately 14% in the feedwater heater area heat loads. Based on a review of design-basis calculations and environmental qualification design temperatures, the above increases are within the available excess design capability. Therefore, the design and operation of the HVAC are not adversely affected by the EPU.

On September 17, 2001, the NRC staff requested additional information regarding the potential impact of the EPU on those HVAC systems discussed in SRP Sections 9.4.2 - 9.4.5. Also, the NRC staff requested that the licensee include a discussion of the impact, if any, during both normal and post-accident operations resulting from increased heat loads due to the EPU and the bases for CP&L's determination of (PDHVAC) systems acceptability post-EPU. The licensee responded in a letter dated October 17, 2001, as follows:

- Reactor Building HVAC System: Reactor Building HVAC system is minimally affected by EPU. The areas of the reactor building affected by EPU are the drywell and the MSIV pit as discussed in Section 6.6 of the PUSAR. The temperature increases in these areas were conservatively calculated to be approximately 1.1°F for the MSIV pit and 1.8°F for the drywell. Based on a review of design-basis calculations and environmental qualification design temperatures, these increases are within the available excess design capability. The design and operation of the reactor building HVAC are not adversely affected by the EPU.
- Turbine Building HVAC System: The Turbine Building HVAC system is minimally affected by the EPU. The areas of the Turbine Building affected by the EPU are primarily the feedwater heater area, areas around condensate piping/pumps and the

main steam tunnel area. As discussed in Section 6.6 of the PUSAR, heat loads in the feedwater heater areas may increase by up to 14%. Local temperatures near pump motors that will be impacted by EPU were evaluated. Based on a review of design-basis calculations and environmental qualification design temperatures, these increases are within the available excess design capability. The design and operation of turbine building HVAC is not adversely affected by the EPU.

- Diesel Generator Building HVAC System: The Diesel Generator Building HVAC system is not affected by EPU. Under EPU conditions, the Diesel Generator remains below rated capacity and there is essentially no electrical loading or process temperature change in this area. Therefore, there is no increase in a design-basis heat load for this area.

- ECCS Pump Room HVAC System: The ECCS Pump Room HVAC system is minimally affected by the EPU. ECCS motors continue to operate at or below rated horsepower for EPU. The ECCS systems' process temperature is not changed, with the exception of the slight increase in suppression pool temperature. The piping heat load temperatures used in the ECCS Pump Room HVAC design bound the increased EPU suppression pool temperature. Therefore, the ECCS Pump Room HVAC system is not adversely affected by the EPU.

- SFP Area HVAC System: The SFP Area HVAC System is not affected by the EPU. The SFP Area Ventilation System is part of the Reactor Building HVAC (i.e., discussed above). The upper limit on the SFP temperature is maintained at the same level as before the EPU as indicated in PUSAR Section 6.3. Therefore, heat load impacts are negligible.

Based on the NRC staff's review of the licensee's rationale, and the experience gained from the review of power uprate applications for other BWR plants, the NRC staff finds that the EPU does not adversely affect the operation of the power-dependent HVAC systems.

6.7 Fire Protection Program

6.7.1 10 CFR 50 Appendix R Fire Event

The NRC staff has reviewed Section 6.7, "Fire Protection," of NEDC-33039P. Based on its review of the licensee's submittal, the NRC staff finds that, consistent with other EPU submittals for BWRs, the operation of BSEP Units 1 and 2 at the EPU RTP level will not affect the design or operation of the plant's fire detection systems, fire suppression systems, or fire barrier assemblies installed to satisfy NRC fire protection requirements, or result in an increase in the potential for a radiological release resulting from a fire. The licensee has stated that any changes to the plant configuration or combustible loading as a result of modifications necessary to implement the EPU will be evaluated under the plant's existing NRC-approved fire protection plan. The NRC staff finds this acceptable.

The licensee performed a thermal-hydraulic analysis of the important plant process parameters following a fire assuming EPU conditions. This analysis indicates an increase in the peak fuel cladding temperature following a fire from less than the current 1200°F to 1468°F with the EPU, which is below the design limit of 1500°F; an increase in the primary containment pressure from the current 6.2 psig to 8.5 psig under the EPU, which is below the design limit of 62 psig, and an increase in the suppression pool bulk temperature from the current 186.5°F to 196.5°F under the EPU, which is below the design limit of 220°F. The NRC staff finds these changes acceptable. All other important plant process parameters such as primary system pressure and drywell airspace temperature remain unchanged. The time available for the plant operations personnel to initiate drywell depressurization and initiate the RCIC system to provide reactor coolant makeup has not changed with the EPU. In order to ensure an adequate hot shutdown capability is provided, the licensee will revise its post-fire safe shutdown procedures to instruct the plant's operations personnel to increase the RCIC system flow to 500 gpm following a fire event at the EPU RTP. The NRC staff finds this acceptable. The licensee made no other changes to the plant's hot shutdown structures, systems, components, or procedures. The licensee has made no changes to the structures, systems, components or procedures necessary to achieve and maintain cold shutdown conditions within 72 hours.

The NRC staff finds that the operation of BSEP Units 1 and 2 at the EPU RTP will not adversely affect the ability of the plant to achieve and maintain safe shutdown conditions following a postulated fire event, and operation at the uprated power level is acceptable.

6.8 Systems and Facilities Not Affected and Insignificantly Affected by EPU

6.8.1 Systems and Facilities Not Affected by EPU

In addition to the systems listed in Table J-1 of ELTR1 and not addressed elsewhere, the licensee stated that the following systems are not affected by operation of the plant at the EPU level:

1. Reactor Protection System (This was originally identified in ELTR1, Table 1-3 as a system dependent on power level. Current EPUs now classify the RPS as not affected because the system logic is unchanged. Changes to RPS trip setpoints occur within the originating systems (e.g., Neutron Monitoring System).

2. Post-Accident Sampling System

3. Torus Drain System

4. Auxiliary Boiler System

5. Turbine Building Sampling System

6. Screen Wash System

7. Emergency AC Lighting System

8. Annunciator and Remote Annunciator Systems

9. Caswell Beach Supervisory and Control System

10. Service Air System

11. Pneumatic Nitrogen System
12. Hydrogen Supply System
13. Carbon Dioxide Supply System
14. Lube Oil Storage and Transfer System
15. Potable Water System
16. Radwaste Sampling System
17. Refueling System
18. Reactor Vessel Service Equipment, New Fuel Storage
19. Spent Fuel System
20. Grounds Maintenance/Landscaping
21. Clean Machine Shop
22. Service Water Building
23. HVAC Service Building
24. Augmented OffGas Building
25. Auxiliary Boiler House
26. Diesel Generator Building
27. Control Building
28. Radwaste Building
29. Water Treatment Building
30. Miscellaneous Structures and Out Buildings
31. Safety Equipment
32. General Instrumentation and Control Spares
33. General Mechanical Spares

The NRC staff has reviewed these systems and facilities, and finds that plant operation at the proposed EPU level has no impact on them.

6.8.2 Systems and Facilities with Insignificant Effect from the EPU

In addition to the systems listed in Table J-2 of ELTR1, the licensee stated that some systems and facilities are affected to a small extent by operation of the plant at the higher EPU level. The licensee stated that for the following systems, the effects are insignificant to the design or operation of the system and equipment:

1. Reactor Building Sampling
2. Condensate Piping and Valves and Condensate Return System
3. Condensate Makeup System
4. Diesel Generator Fuel Oil System
5. Site Cables (Wiring, Trays, and Conduit)
6. Main Control Board
7. Auxiliary Control Board
8. Instrument Air System
9. Fuel Oil System
10. Water Treatment System
11. Demineralized Water System
12. Hydrogen Water Chemistry
13. Reactor Building
14. Turbine Building

The NRC staff has reviewed these systems and facilities, and finds that plant operations at the proposed EPU level has insignificant effect on their operation.

7.0 POWER CONVERSION SYSTEMS

7.1 Turbine-Generator

The turbine-generator was originally designed to have the capability to operate continuously at 105% of rated steam flow (10.050 Mlb/hr at a throttle pressure of 965 psia). The licensee stated that as a result of plant operations at the proposed EPU level, the turbine will be modified to operate with an increased rated steam flow of 12.373 Mlb/hr at a throttle pressure of 973 psia to maintain the GE standard flow margin of 3% of the proposed EPU rate steam flow. The turbine modifications (including the overspeed trip settings that may have to be changed due to the large increase in flow, and the mechanical overspeed trip device that may have to be modified or replaced) are needed.

The licensee performed evaluations to ensure that design limits of the turbine-generator and its components are not exceeded and that plant operations remain acceptable at the proposed EPU. These components included both stationary and rotating components, valves, control systems, and other support systems.

Based on the information submitted, and the licensee's rationale and evaluation, the NRC staff finds that operation of the turbine-generator at the proposed uprate power level is acceptable.

7.2 Miscellaneous Power Conversion Systems

The NRC staff has reviewed the following system evaluation provided by the licensee:

7.2 Condenser and Steam Jet Air Ejectors

7.3 Turbine Steam Bypass

7.4 Feedwater and Condensate System

7.4.1 Normal Operations

7.4.2 Transient Operation

7.4.3 Condensate Demineralizers

The licensee evaluated the miscellaneous steam and power conversion systems and their associated components (including the condenser and steam jet air ejectors, turbine steam bypass, and feedwater and condensate systems) for plant operation at the proposed EPU level. The licensee stated that the existing equipment for these systems is acceptable for plant operations at the proposed EPU level.

Although these systems do not perform any safety-related function, the NRC staff evaluated the impact of plant operation at the proposed EPU level on the design and performance of these systems and found it to be insignificant.

8.0 RADWASTE SYSTEMS AND RADIATION SOURCES

8.1 Liquid Waste Management

The liquid radwaste system collects, monitors, processes, stores, and returns processed radioactive waste to the plant for reuse or for discharge.

The single largest source of liquid and wet solid waste is from the backwash of the condensate filter-demineralizers. The licensee stated that plant operations at the proposed EPU level causes an increase in flowrate through the filter-demineralizers, resulting in a slight reduction in the average time between backwashes. This reduction does not affect plant safety. Similarly, the RWCU filter-demineralizer requires more frequent backwashes due to slightly higher levels of fission products.

The activated corrosion products in liquid wastes are expected to increase proportionally to the EPU. However, the total volume of processed waste is not expected to increase appreciably, since the only significant increase in processed waste is due to the more frequent backwashes of the condensate filter-demineralizers and RWCU filter-demineralizers. The licensee performed evaluations of plant operations and effluent reports, and concluded that the requirements of 10 CFR Part 20 and 10 CFR Part 50 Appendix I will continue to be satisfied.

Based on the review of the licensee's rationale, the NRC staff agrees with the licensee's conclusion and finds the liquid radwaste system acceptable for plant operations at the proposed EPU level.

8.2 Gaseous Waste Management

Gaseous wastes generated during normal and abnormal operation are collected, controlled, processed, stored, and disposed of utilizing the gaseous waste processing treatment systems. These systems, which are designed to meet the requirements of 10 CFR Part 20 and 10 CFR Part 50 Appendix I, include the offgas system and various building ventilation systems. Non-condensable radioactive gas from the main condenser, along with air inleakage, is continuously removed from the main condenser by steam jet air ejectors and is discharged into the offgas system. Building ventilation systems control airborne radioactive gases by using a combination of devices such as High Efficiency Particulate Air and charcoal filters, and radiation monitors that signal automatic isolation dampers or trip supply and/or exhaust fans, or by maintaining negative air pressure, where required, to limit migration of gases. The licensee stated that the airborne effluent activity released through building vents is not expected to increase significantly with the EPU. The release limit is an administratively controlled variable, and is not a function of core power. The gaseous effluents are well within limits at original power operation and are determined to remain within limits following EPU implementation.

Based on NRC staff review of the licensee's rationale and evaluation, and the experience gained from our review of power uprate applications for other BWR plants, the NRC staff finds that plant operations at the proposed uprate power level will have an insignificant impact on the above systems.

8.2.1 Offgas System

Core radiolysis (i.e., formation of H_2 and O_2) increases linearly with core power, thus increasing the heat load on the offgas recombiner and related components. The licensee evaluated the impact of the increases of these offgases resulting from plant operation at the proposed EPU on the offgas system. The licensee stated that these operational increases in offgas due to EPU remain well within the design capacity of the system. The system radiological release rate is administratively controlled, and does not change with operating power. Therefore, EPU does not affect the offgas system design or operation.

The NRC staff finds the licensee's conclusion that the BSEP operations at the proposed EPU will have an insignificant impact on the offgas systems acceptable.

8.3 Radiation Sources in the Core

This section also includes the NRC staff's evaluation of 8.3.1, Normal Operation, and 8.3.1, Normal Post-Operation.

The NRC staff has reviewed the licensee's plan for power uprate with respect to its effect on the facility radiation levels and on the radiation sources in the core and coolant. The radiation sources in the core include radiation from the fission process, accumulated fission products, and neutron reactions as a secondary result of reactor power. The radiation sources in the core are expected to increase in proportion to the increase in power. This increase, however, is bounded by the existing safety margins of the design basis sources. Since the reactor vessel (inside fully-inerted primary containment) is inaccessible during operation, an approximately 15 percent increase in the radiation sources in the reactor core will have no effect on occupational worker personnel doses during power operation. Due to the shielding design and containment surrounding the reactor vessel, worker occupational doses are largely unaffected, and doses to the public from radiation shine from the reactor vessel remain essentially zero as a result of the EPU. However, impact from potential increases in calculated doses to the public from radiation shine (nitrogen-16 skyshine) from main steamline, turbine, and steam heater sources is discussed in the NRC staff's Environmental Assessment (and summarized in this SE), and plant occupational radiation levels and worker doses are discussed in this SE.

The second set of post-operation source data consists of tabulated isotopic activity inventories for fission products in the fuel. These are used for post-accident evaluations. Most fission product inventories reach equilibrium within a three-year period. The inventories of these fission products, as well as the inventories of the longer-lived fission products, can be expected to increase in proportion to the thermal power increase. The results of the post-accident evaluations using these revised fission product activities are contained in Section 9 of this SE.

On the basis of experience gained from its review of EPU applications for other BWR plants and for the reasons described above, the NRC staff finds the level of the radiation sources in the reactor core following the EPU to be acceptable.

8.4 Radiation Sources in the Reactor Coolant

This section also includes the NRC staff's evaluation of 8.4.1, Coolant Activation Products, 8.4.2, Activated Corrosion Products, and 8.4.3, Fission Products.

During operation, the reactor coolant passing through the reactor core region becomes radioactive as a result of nuclear reactions. The activation product concentrations in the steam will remain nearly constant following the EPU since the increase in activation production in the steam passing through the core will be balanced by the increase in steam flow through the core. However, because of the decreased steam transit time (less decay-time), the radiation levels in the turbine building from activation products (chiefly nitrogen-16) in the steam will increase in approximate proportion to the thermal power increase. The activation products (and radiation levels) in the reactor water also increase in approximate proportion to the increase in thermal power. The installed shielding at Brunswick was conservatively designed so that the increase in activation products in the reactor coolant resulting from the proposed power uprate should not affect the conservative radiation zoning in the plant.

Activated corrosion products (ACPs) from the activation of metallic corrosion/wear materials in the reactor coolant could increase as a result of the proposed EPU. The equilibrium level of ACP in the reactor coolant is expected to increase in proportion to both the increase in feedwater flow rate and the increase in neutron flux in the reactor, while the increased feedwater flow will likely reduce the efficiency of the RWCU. However, the expected ACP increase should not exceed the design-basis concentrations. Most of the areas (e.g., recirculation pumps and the RWCU) that would be significantly affected by this increase in ACP are located in locked areas, such as the drywell (primary containment), that are inaccessible during plant operation. Since these areas are usually (pre-EPU) high dose rate areas, personnel access to these areas outside the drywell will continue to be restricted during plant operations as required by 10 CFR Part 20 high radiation area requirements, and in accordance with plant TS and required licensee implementing procedures. Fission products in the reactor coolant result from the escape of minute fractions of the fission products that are contained in the fuel rods. Fission product release into the primary coolant is dependent on the nature and number of fuel defects and is approximately linear relative to core thermal power. Using ANSI/ANS 18.1-1976 normal operations source term methodology, the licensee calculated about a 14% increase in fission product concentration in the reactor coolant from the fuel (assuming no increase in fuel cladding defects). However, the fission product concentration in the steam should remain nearly constant following the power uprate, given the proportional increase in steam flow (dilution) through the core. Given that current levels of fission product activity in the reactor coolant and steam are small fractions of the design-basis levels, a 14% increase should have a minimal impact on worker doses, and the NRC staff finds this acceptable.

8.5 Radiation Levels

This section also includes the NRC staff's evaluation of 8.5.1, Normal Operations, 8.5.2, Normal Post-Operation, and 8.5.3, Post-Accident Operations.

Radiation sources in the reactor coolant contribute to the plant radiation levels. As discussed previously, the proposed 15% power uprate will result in an approximate proportional increase in certain radiation sources in the reactor coolant. This increase in reactor coolant activity will result in some increases (up to 15%) in radiation levels in accessible areas of the plant. This increase in plant radiation levels may be higher in certain areas of the plant (e.g., inside the drywell and near the RWCU) due to the presence of ACP. Some post-operational radiation levels may also be higher in those areas of the plant where accumulation of corrosion product crud (activated corrosion and wear products) is expected (i.e., near the SFP cooling system piping and the reactor coolant piping as well as near some liquid radwaste equipment). Many of these areas are normally locked, controlled in accordance with 10 CFR Part 20 human reliability analysis requirements, and require infrequent access.

The licensee stated that many aspects of the plant were originally designed for higher-than-expected radiation sources. Therefore, the small potential increase in radiation levels resulting from the proposed power uprate will not significantly affect radiation zoning or shielding in the various areas of the plant that may experience higher radiation levels. However, to reduce radiation levels from nitrogen-16 (N-16), the licensee installed additional permanent shielding in and around the steam turbine buildings in 1998. The additional shielding effectively reduced the radiation levels by about 18%, thereby effectively reducing the potential increases in worker and public doses from the N-16 increases resulting from the EPU. This shielding initiative is an example of the licensee's as low as is reasonably achievable (ALARA) program. The purpose of the licensee's ALARA program is to ensure that doses to individual workers will be maintained within reasonable, acceptable levels. The licensee will continue to use procedural access, work planning and controls, source term reduction, shielding, and pre-job worker training/briefings to compensate for any increased plant radiation levels and to maintain occupational doses ALARA. As part of the overall EPU test program, during the incremental <5% power step increases, the licensee will perform special surveys for monitoring area external radiation levels to assure that the radiation and high radiation areas are properly designated, posted, and controlled as required by 10 CFR Part 20 and plant TS.

Several physical plant modifications will need to be completed over the next two refuelings, prior to full implementation of the power rate increase. These modifications will be planned and conducted in accordance with the station ALARA program and the requirements of 10 CFR Part 20. The resultant one-time occupational collective dose should be a small fraction of the units' average yearly worker collective dose for the units.

The proposed power uprate and the use of the AST results in calculated increases in post-accident radiation levels from a postulated LOCA. Item II.B.2 of NUREG-0737 states that the occupational worker dose guidelines of GDC-19 (10 CFR Part 50, App. A) shall not be exceeded during the course of an accident. Compliance with Item II.B.2 ensures that operators can access and perform required duties and actions in designated vital areas. GDC-19 requires that adequate radiation protection be provided such that the dose (excluding inhalation dose) to personnel should not exceed 5 rem whole body or its equivalent to any part of the body for the duration of the accident. The licensee used the AST as the basis for the EPU accident source term calculation, and the AST worker dose acceptance criterion is no more than 5 rem total effective dose equivalent (TEDE). Based on conservative calculations using AST methodology, the licensee has determined that the post-accident radiation levels will increase by approximately 15% as a result of the proposed power uprate. The calculated post-accident vital area worker TEDE for the post-accident coolant and gas sampling, and standby gas treatment system stack sampling emissions, are less than 4.5 rem, 3.0 rem, and 4.8 rem, respectively. Additionally, the calculated dose estimates for personnel performing required post-LOCA, vital area duties in the plant's combined Technical Support Center and Emergency Operations Facility are less than 0.7 rem TEDE, well below the GDC limit. The calculated operator dose in the control room is 1.29 rem TEDE, which is well below the 5 rem GDC limit. Therefore, personnel access to and work in designated vital areas for accident mitigation missions following a LOCA can be accomplished without exceeding the dose requirements of GDC-19. The NRC staff finds this acceptable.

8.6 Normal Operation Off-Site Doses

For the EPU, normal operation gaseous activity levels are expected to increase in proportion to the percentage increase in core thermal power. The Brunswick TS implement the limits of 10 CFR Part 20 and the guidelines of 10 CFR 50, Appendix I. At the CRTP, the radiation effluent doses are a small fraction of the doses allowed by TS limits. The EPU will not involve significant increases (no more than 15%) in the offsite doses from noble gases, airborne particulates, iodine, or tritium, as governed by Appendix I. Using the highest calculated dose over the period of 1996-2000, this assumed effluent release increase from the EPU would result in the worst-case offsite pathway dose (in terms of the 30 mrem site limit) of less than 3% of the 10 CFR Part 50, Appendix I numerical design objectives. The licensee has calculated and conservatively estimated the annual pre-EPU dose at the site boundary from N-16 skyshine and gaseous effluents for continuous occupancy at pre-EPU conditions. Because of the additional turbine building shielding, the calculated skyshine dose at the site boundary after the EPU should approximate the pre-EPU levels. The total annual whole body dose at the site boundary is estimated to be about 7 mrem, which is approximately 28% of the 40 CFR 190 limit of 25 mrem. Given a 15% increase from the EPU in the site boundary dose, the licensee conservatively estimates that the highest dose would be about 33% of the 40 CFR 190 limit. Therefore, any increase in offsite doses due to the EPU will be well below the limits of 10 CFR 20, 10 CFR 50, Appendix I, and 40 CFR 190. The NRC staff finds this acceptable.

9.0 REACTOR SAFETY PERFORMANCE EVALUATION

9.1 Reactor Transients

The SRP (NUREG-0800) provides guidelines to assure that: (1) pressure in the reactor coolant and main steam system should be maintained below 110 percent of the design values according to the ASME Code, Section III, Article NB-7000, “Overpressure Protection”; (2) fuel cladding integrity should be maintained by ensuring that the reactor core is designed to operate with appropriate margin to specified limits during normal operating conditions and AOOs; (3) an incident of moderate frequency should not generate a more serious plant condition unless other faults occur independently; and (4) an incident of moderate frequency, in combination with any single active component failure or single operator error, should not result in the loss of function of any fission product barrier other than the fuel cladding. A limited number of fuel cladding perforations are acceptable.

The BSEP Units 1 and 2 UFSAR contains evaluation of a wide range of potential transients. Chapter 15 of the UFSAR contains the design-basis analyses that evaluate the effects of an AOO resulting from the changes in system parameters such as (1) a decrease in core coolant temperature, (2) an increase in reactor pressure, (3) a decrease in reactor core coolant flow rate, (4) reactivity and power distribution anomalies, (5) an increase in reactor coolant inventory, and (6) a decrease in reactor coolant inventory. For the initial reload at the ORTP, all events in these categories were analyzed to determine the impact of these transients on the RCPB and the fuel cladding integrity. The limiting events are analyzed on a cycle-specific basis to establish the thermal limits that will ensure the plant’s operation would not lead to loss of fuel integrity.

The NRC staff-accepted ELTR1 guidelines recommend that a set of transient events be analyzed to verify that the operation at the increased thermal power would not change the severity of these transients in terms of change in the MCPR, reactor pressure, and power. The ELTR1 transients were analyzed using an equilibrium core to demonstrate that the plants could operate at the increased thermal power and meet the specified fuel design limits.[

] For each plant, the limiting cycle-specific reload transients are identified in the plant's UFSAR, although similar transients are limiting for most BWRs. Additional transient analyses are performed to support implementation of operating flexibility (i.e., new fuel introduction, implementation of higher rod line, operation at increased core flow), in accordance with the NRC-approved GE licensing document, GESTAR II.

The licensee analyzed the LOFW transient, using a GE14 equilibrium core, to evaluate the performance of the RCIC under the EPU condition. Table 1.0 identifies the ELTR1 events, the reload transients performed for Unit 1 Cycle 14, and the basis for the deviation. Some of the transients that were recommended to be performed in ELTR1, that the licensee took an exception to, are discussed below.

The Pressure Regulator Downscale Failure (PRDF) event is considered to cause a mild pressure and power change and is bounded by other events in the category. In addition, the plant is equipped with a backup regulator. Therefore, the NRC staff accepts the disposition of this event.

Appendix E of ELTR1 does include a loss-of-single-feedwater pump-transient, but the licensee considers this event to be non-limiting with respect to MCPR and thus did not analyze it. The NRC staff agrees with this assessment because it is bounded by the LOFW event analysis.

The main steam isolation valve closure - direct (MSIVD) is mitigated by the direct scram signal on valve position. Earlier valve position scram reduces power level in comparison with the MSIV closure due to the flux scram closure case analyzed for ASME overpressure evaluation. This is a pressurization transient recommended in the ELTR1 for the EPU operation.

Similarly, ELTR1 recommended turbine trip with bypass and load reject with bypass to be analyzed for the EPU operation to verify the trend at the EPU power level relative to the response of the transients at the CRTP. These are medium-level pressurization transients that also affect the MCPR change. [

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[

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Moreover, Appendix A of the November 28, 2001, supplement provided further justification for the deviations from the ELTR1 guidelines. The licensee stated that:

1. GE experience shows that a change in the OLMCPR due to the constant pressure EPU is small, and nothing is gained by performing analyses based on representative equilibrium core design parameters.

2. [

]

BSEP Units 1 and 2 Transient Disposition
Table 1.0

Event Category	ELTR1 Events	Reload Events	Deviation and Basis
1. Decrease in Core Coolant Temperature	LFWH FWCF	LFWH FWCF	Disposition: Limiting for events in this category (LFWH and FWCF) will be analyzed during the reload analysis. Status: LFWH and FWCF was analyzed for B1C14
2. Increase in Reactor Pressure	LRNBP (no BP) LRWBP (w BP) TTNBP TTWBP PRFD MSIVD (direct) 1 MSIV Closure MSIVF (flux)	LRNBP TTNBP MSIVF (closure Flux Scram)	Disposition: -Limiting reload events will be analyzed during the reload analysis. [ ] Status: -LRNBP,TTNBP & MSIVF analyzed for B1C14.
3.Decrease in Core Coolant Flow Rate	None	None	Disposition: All events in this category are considered non-limiting for all BWRs, except for SLO pump seizure. Status: This event was analyzed for the GE14 introduction and MCPR limits were developed.
4.Increase in Core Flow Rate	(1)Slow RR flow increase K(F), MCPR (F) (2) Fast RR flow Increase	K(F), MCPR (F) applicability confirmation	Disposition: -The MCPR (F) or K(F) curves are based on the hypothetical slow RR flow increase event. This analysis is performed to bound all possible flow runup events along conservative rod line (e.g MELLLA). Status: -Confirmed generic remains applicable for B1C14. Disposition: -Event limits bounded by the generic off-rated power and flow dependent limits. Status: -BSEP off-rated limits remain applicable
5.Increase in Reactor Coolant Inventory	Inadvertent HPCI	Inadvertent HPCI	Disposition: -The event is bounded by LFWH Status: -Confirmed B1C14 LFWH bounds this event.
6.Decrease in Reactor Coolant Inventory	(1) LOFW (2)One FW pump Trip	None	Disposition: None Status: LOFW analyzed for EPU [ ]
7.Increase in Reactivity	RWE	(1)RWE (2)Mislocated/ misoriented Bundle	Disposition: - RWE bounding Status: -RWE and mis-oriented analyzed for B1 C14. Mislocated evaluated and determined to be bounded for B1 C14.
8.Increase in Coolant Temp.	None	None	-No BWR events are limiting for this category

9.2 <u>Confirmation of the Cycle-Specific Analysis Performed for Unit 1, Cycle 14</u>

Since BSEP Unit 1 implemented the first stage of the EPU in March 2002 for Cycle 14, the licensee performed a cycle-specific reload analysis at the CRTP and at the EPU power level. During the on-site review, the NRC staff evaluated the events analyzed and the unit's response at the two power levels. The analysis included the performance improvement features that support the plant operation under different conditions. [

] Due to the introduction of the GE14 fuel, the licensee evaluated the SLO recirculation pump seizure event and confirmed the plant-specific power and flow-dependent limits remained applicable. Based on the results of the audit, and the use of approved methodologies, the NRC staff concludes that the licensee has appropriately performed the [ ] analysis at the EPU condition to demonstrate the unit's ability to operate at the EPU condition without exceeding the fuel design limits during an AOO. Moreover, the licensee will perform cycle-specific reload analyses based on the actual core design and the EPU conditions to support operation at the full EPU power level in Cycle 15 for Unit 1 (March 2004).

In comparing the Unit 1 transient response for operation at the CRTP and at the EPU power level, the NRC staff made the following observations: (1) the bundle power would be higher for the EPU operation; (2) the number of SRV OOS and ADS OOS service is reduced from 2 for the CRTP to 1 for the EPU, indicating a reduction in the extra relief capacity at the EPU conditions; (3) the change in the MCPR for some of the limiting transients is slightly lower for the EPU conditions relative to the CRTP, although to achieve the full EPU the core design would be different; and (4) the results of the cycle-specific ASME overpressure transient did increase for the EPU condition (1314/1343 psig for CRTP/EPU).

For Unit 2, the licensee is deferring the EPU AOOs to the reload analysis. This is a deviation from the ELTR1 guidelines. However, in the Unit 1, Cycle 14 analysis, the licensee demonstrated that the analyses would be performed as required and the MCPR changes due to the higher thermal power are within the expected range.

Based on the NRC staff's audit, the RAI responses, the review of the information provided in the submittal, and the licensee's use of approved methodologies to perform the evaluations, the NRC staff accepts the licensee's approach. The NRC staff concludes that the EPU transient analyses do not identify any major changes to the basic characteristics of any of the limiting events due to the EPU operating conditions.

9.3 <u>Design-Basis Accidents</u>

This evaluation was performed separately as part of the licensee's amendment request for full-scope implementation of the AST.

9.4 <u>Special Events</u>

9.4.1 Anticipated Transient Without Scram

An ATWS is defined as an AOO with failure of the reactor protection system (RPS) to initiate a reactor scram to terminate the event. The requirements for ATWS are specified in 10 CFR

50.62. The regulation requires BWR facilities to have the following mitigating features for an ATWS event:

1. An SLC system with the capability of injecting a borated water solution with reactivity control equivalent to the control obtained by injecting 86 gpm of a 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel;

2. An alternate rod insertion system that is designed to perform its function in a reliable manner and that is independent from sensor output to the final actuation device; and

3. Equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

BWR performance during an ATWS is also compared to the criteria used in the development of the ATWS safety analyses described in NEDO-24222, “Assessment of BWR Mitigation of ATWS, Volume II” (Ref. 13). The criteria include (a) limiting the peak vessel bottom pressure to less than the ASME Service Level C limit of 1500 psig, (b) ensuring that the PCT remains below the 10 CFR 50.46 limit of 2200°F, (c) ensuring that the cladding oxidation remains below the limit in 10 CFR 50.46, (d) limiting peak suppression pool temperature to less than 207.7°F (based on the LOCA results), and (e) limiting the peak containment pressure to a maximum of 62 psig containment design pressure.

The ATWS analyses assume that the SLC system will inject within a specified time to bring the reactor subcritical from the RTP and maintain the reactor subcritical after the reactor has cooled to the cold shutdown condition. For every core reload, the licensee evaluates how plant modifications, reload core design, changes in fuel design, and other reactor operating changes affect the applicability of the ATWS analysis-of-record.

The licensee stated that BSEP Units 1 and 2 meet the ATWS mitigation requirements defined in 10 CFR 50.62, because (a) an alternate rod insertion system is installed, (b) the boron injection capability is equivalent to 86 gpm, and (c) an automatic ATWS-recirculation pump trip logic has been installed. Section L.3 of ELTR1 discusses the ATWS analyses and provides a generic evaluation of the following limiting ATWS events in terms of overpressure and suppression pool cooling: (a) MSIV closure, (b) PRFO, (c) loss of offsite power (LOOP), and (4) inadvertent opening of a relief valve. The licensee analyzed the ATWS events based on representative GE14 fuel equilibrium core, operating at the EPU operating condition to demonstrate that BSEP Units 1 and 2 meet the ATWS acceptance criteria. The licensee analyzed all four ATWS events identified in ELTR and the most limiting events (PRFO and MSIVC) were analyzed at beginning-of-cycle and end-of-cycle conditions.

An ATWS event under EPU conditions has the same characteristics and requires the same operator actions as under pre-EPU conditions. The plant operating staff will be able to identify and respond to an ATWS event as under the current power level. Boron injection was assumed to start at the boron injection initiation temperature or 120 seconds after the ATWS-RPT trip (i.e, low reactor water level or high reactor pressure), whichever is later. Based on the data obtained during an audit, the NRC staff determined that the boron injection initiation temperature occurs before 120 seconds; therefore, SLC injection was assumed to begin 120 seconds after the ATWS-RPT. During the NRC staff’s audit of the calculations, the NRC staff noted that SLC injects 123.9 seconds, 144.2 seconds, and 120.8 seconds after the start of the event for the MSIVC, PRFO and LOOP events, respectively. Before the EPU, the SLC injects at 124.1 seconds and 137.6 seconds for the MSIVC and PRFO events, respectively. Therefore, the difference in the SLC injection time did not change significantly between the OLTP and the EPU conditions. The licensee determined that the operator action response time is not expected to be less than 79 seconds, and based on the ATWS analysis at the EPU condition, the operators have between 79 seconds and 120 seconds to initiate the SLC.

Table 9-6 of the PUSAR lists the key input parameters used in the ATWS analyses and Table 9-7 provides the ATWS results for the EPU operation and the baseline case. The PUSAR reports (1) a peak vessel bottom pressure of 1492 psig, compared to the limit of 1500 psig, (2) a PCT of 1309°F, compared to the 2200°F limit, (3) a peak suppression pool temperature of 195.5°F, compared to the limit of 207.7°F, and (4) a peak containment pressure of 12.7 psig, compared to the design limit of 62 psig.

The pressure response for all of the analyzed ATWS events reviewed by the NRC staff for the SLC relief margin evaluation indicates that for some events, the SRVs with the highest setpoints would lift to maintain the peak pressure below the limit, although in general it is sufficient for the SRVs with the lowest setponts to lift to maintain the reactor pressure. In addition, the ATWS peak vessel pressure reported in the PUSAR is close to the limit (1492/1500 psig). Therefore, the NRC staff evaluated which unit would be limiting for each event. BSEP Unit 1 has a turbine bypass capacity of 23.8 percent of the CRTP reactor steam flow, which corresponds to 20.6 percent of the EPU rated steam flow. BSEP Unit 2 has a bypass capacity of 80.3 percent of the CRTP steam flow and for the EPU condition, the capacity becomes 69.6 percent of the EPU rated steam flow. The PRFO event response is affected by the bypass capacity and yields the peak pressure and cladding temperature. In the sequence for this event, the failure of the pressure regulator to achieve the full demand position causes the turbine and bypass valves to open to full capacity and the reactor pressure drops until isolation occurs. The reactor pressure recovers after the MSIV closes and the SRVs lift to maintain pressure. The unit with the larger turbine bypass capacity (SRV capacity being the same) would depressurize faster and isolate earlier, resulting in a higher peak pressure. BSEP Units 1 and 2 are analyzed to operate with bypass valves out-of-service (as defined in the COLR); however, the PRFO event would be more limiting with all bypass valves operable for Unit 2. In a telephone conference call, followed by an RAI, the NRC staff asked the licensee if Unit 2 had been analyzed for the PRFO event. The licensee responded that the ATWS analysis was based on Unit 1, which is limiting for the LOOP event. However, since Unit 2 would be limiting for the PRFO and this ATWS event yields the peak vessel pressure, the licensee reanalyzed this event using the Unit with the highest bypass capacity.

However, in the PRFO reanalysis, the licensee reduced the high setpoint drift value from the 44 psig originally used by GENE to 34 psig, based on the 3% tolerance for the SRVs. Therefore, the ATWS reanalysis is based on 10 operable SRVs lifting 10 psig lower than the setpoints used in the ATWS results reported in the PUSAR. This would be expected to yield a lower vessel pressure. In a March 11, 2002, telephone conference, GENE stated that the 44 psig drift was based on the performance of the two-stage Target Rock valves that historically exhibited a high propensity to drift. CP&L reported that the BSEP Units 1 and 2 SRVs are two-stage Target Rock valves, but the valve disks had been modified to reduce the propensity to drift. Subsequent surveillance testing (discussed in Section 3.1, "Nuclear System Pressure Relief") indicated that the BSEP SRVs do not experience a setpoint drift greater than 3 percent.

CP&L stated that the 3-percent SRV tolerance's limits were approved during the 5-percent power uprate amendment for BSEP Units 1 and 2 (Amendments 183 and 214). The SRV tolerances are specified under the TS surveillance requirement (SR) 3.4.3.1. In addition, Section 3.1.1 of the PUSAR discusses the results of inservice testing of the high setpoint drift of the BSEP SRVs. The NRC staff accepts the change to the high setpoint drift value from 44 psig to 34 psig in the ATWS reanalysis, because the NRC staff had previously reviewed and approved the 3-percent tolerances specified in SR 3.4.3.1.

In response to RAI 5-14a, the licensee stated that no other key input parameter used in the ATWS analysis reported in the PUSAR changed for the PRFO reanalysis, and all of the Unit 2 bypass valves were assumed to be operable. The licensee determined that the increase in the analyzed turbine bypass capacity from 20.64 percent (Unit 1) to 69.6 percent (Unit 2) results in peak reactor pressure increase of 2 psig. However, the decrease in the SRV setpoint uncertainty from 44 psig to 34 psig yields a decrease in the peak reactor pressure of 7 psig. Therefore, the licensee reports a net reduction in the peak vessel pressure from 1492 psig as shown in Table 9-7 of the PUSAR to 1487 psig. In a March 20, 2002, telephone conference, the licensee confirmed that Unit 1 was the most limiting unit for the MSIV closure event. The licensee documented this in RAI response 5-14a, stating that for all analyzed ATWS events, the most limiting parameter from each unit was used, thereby providing a bounding ATWS analysis. Therefore, the NRC staff accepts the results of the PRFO ATWS reanalysis since the licensee (1) reanalyzed the limiting event in terms of peak pressure response, (2) used the unit with the largest bypass capacity, and (3) the key input parameters were not changed, except for the plant-specific SRV tolerance.

During the review of the audit material, the NRC staff determined that the ATWS analysis assumed an SRV throat diameter of 5.03 inches and a smaller SRV size at the plant would indicate that the ability of the plant to reduce pressure during an ATWS event could be lower than the analyzed condition. This could affect the results of the ATWS analysis. Therefore, the NRC staff asked the licensee to confirm that both units meet the assumed SRV throat size. The licensee stated that since the EPU ATWS analysis results are based on a larger SRV diameter than used in the 105% uprate evaluation, a confirmation of the field configuration will be performed prior to operation at the EPU condition. In the response to RAI 5-14a, the licensee stated that the SRVs on both BSEP Units 1 and 2 have been verified, by field walkdown, to have the analytically assumed throat diameter of 5.03 inches. The licensee performed the Unit 2 walkdown in the March 2001 refueling outage and completed the Unit 1 walkdown in the March 2002 refueling outage. Thus, the NRC staff accepts that the BSEP Units 1 and 2 SRVs' pressure relief capacity meets the assumed capability.

Based on the information submitted and reviewed during the audit, the responses to the RAIs, the results presented and the use of NRC-approved codes in the analysis, the NRC staff finds that the EPU ATWS analyses for BSEP Units 1 and 2 are acceptable. BSEP Units 1 and 2 meet the ATWS rule stipulated in 10 CR 50.62 and the results of the ATWS analyses for EPU operation meet the ATWS acceptance criteria.

9.4.2 Station Blackout

9.4.2.1 Reactor Systems Engineering Evaluation

Under 10 CFR 50.63, the reactor core and the associated coolant, control, and protection systems must have sufficient capacity to cool the core and maintain containment integrity in the event of an SBO of a specified duration. The licensee must analyze the plant's capability to cope with an SBO of specified duration. RG 1.155 described a method that is acceptable to the NRC staff to meet the requirements of 10 CFR 50.63. NUMARC 87-00 also provided guidance acceptable to the NRC staff. Table 1 of RG 1.155 provided a cross-reference to the NUMARC 87-00, with notes on where the RG takes precedence.

The licensee has evaluated the capability of BSEP Units 1 and 2 to cope during an SBO using the guidelines in NUMARC 87-00. The higher EPU power level increases the decay heat, which affects the plant's responses and coping capabilities during an SBO. BSEP Units 1 and 2 are classified as a 4-hour SBO duration plant. The licensee stated the EPU conditions would not change the 4-hour coping time or the systems and equipment used to respond to an SBO.

The licensee stated that the current CST design ensures that adequate water volume is available to remove the decay heat and depressurize the vessel. In an RAI response, the licensee reported that a CST tank inventory of 100,000 gallons is currently reserved for the operation of the HPCI system and with HPCI controlling level between L2 and L8, a CST inventory of 86,000 gallons was sufficient to maintain adequate cooling and core coverage.

The higher decay heat for the EPU operation would increase the boil-off rate, thus affecting the make-up water required and the ability of the units to maintain core coverage. Since the licensee confirmed that sufficient CST make-up inventory is available, and the units can maintain adequate cooling and core coverage to the TAF during the coping period, the NRC staff accepts that BSEP Units 1 and 2 will continue to comply with the requirements in 10 CFR 50.63 for the EPU operation.

The licensee stated that the plant response and coping capabilities for an SBO event are impacted slightly by plant operations at the proposed EPU level due to the increase in the decay heat. The licensee, using the guidelines of NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," evaluated the impact of this increase in decay heat on the condensate requirement and the temperature heat-up resulting from loss of ventilation due to an SBO event in the areas that contain equipment necessary to mitigate the SBO event. The evaluation shows that all room temperatures during the SBO event are within the currently analyzed environmental qualification temperature envelope and the equipment qualification bases. SBO containment conditions are enveloped by the peak temperatures and pressures analyzed for an EPU LOCA. The licensee concluded that no changes to the systems and equipment used to cope with an SBO event are required.

Based on the review of the licensee's rationale, the NRC staff finds that the impact due to plant operations at the proposed EPU level on the systems/equipment required to cope with an SBO event is insignificant.

9.4.2.2 Electrical Engineering Evaluation

The licensee re-evaluated SBO using the guidelines of NUMARC 87-00. The plant responses to and coping capabilities for an SBO event are affected slightly by operation at the EPU level, due to the increase in the decay heat. There are no changes to the systems and equipment used to respond to an SBO, nor is the required coping time changed. The licensee evaluated the areas containing equipment necessary for the effect of loss of ventilation due to an SBO. The evaluation shows that equipment operability is ensured due to conservatism in the existing design and qualification bases. The battery capacity remains adequate to support HPCI after the EPU. The current CST design ensures that adequate water volume is available to remove decay heat and depressurize the reactor. The NRC staff determined that the peak containment pressures and temperatures remain within the design bases. The plant meets the requirements of 10 CFR 50.63, "Loss of all alternating current power," and will not be affected at the EPU condition.

10.0 ADDITIONAL ASPECTS OF EXTENDED POWER UPRATE

10.1 High-Energy Line Breaks

10.1.1 Temperature, Pressure, and Humidity Profiles

The licensee's plan to achieve the proposed higher reactor thermal power at the BSEP is to expand the operating envelope on the power/flow map along the current licensed MELLLA line. Operation at the EPU level does not require an increase in the reactor vessel dome pressure over the pre-EPU value to supply more steam to the turbine. Therefore, plant operations at the EPU level will have an insignificant impact (due to changes in the fluid conditions, i.e., pressure or enthalpy, within the system piping) to the mass and energy release rates following an HELB outside the primary containment.

The licensee performed HELB analyses evaluation for the following high energy lines:

- Main Steam
- Feedwater
- ECCS
- RCIC
- RWCU
- Core Spray
- RHR

These HELB analyses were previously evaluated as described in the UFSAR. The evaluations show that the existing pressure and temperature profiles, used to qualify the safety-related equipment and systems outside the primary containment, remain valid.

Based on the review of the licensee's rationale and evaluation, the NRC staff finds that the existing analyses for HELB at the BSEP remain bounding and are acceptable for plant operations at the proposed EPU level.

10.1.2 Equipment Dynamic Qualification

This section evaluates NEDC-33039P Sections 10.1.2, Pipe Whip and Jet Impingement, and 10.3.3, Mechanical Component Design Qualification.

The licensee evaluated equipment qualification for the power uprate condition. The plant-specific dynamic loads such as SRV discharge and LOCA loads (including pool swell, condensation oscillation, and chugging loads) that were used in the equipment design will remain unchanged as discussed in Section 4.1.2 of NEDC-33039P, since these loads are based on the range of test conditions for the design-basis analysis at BSEP, which are bounding for the power uprate condition.

Based on its review of the proposed power uprate amendment, the NRC staff finds that the original seismic and dynamic qualification of safety-related mechanical and electrical equipment is not affected by the power uprate conditions for the following reasons:

1. The seismic loads are unaffected by the power uprate;
2. No new pipe break locations or pipe whip and jet impingement targets are postulated as a result of the uprated condition;
3. Pipe whip and jet impingement loads do not increase for the power uprate; and
4. SRV and LOCA dynamic loads used in the original design basis analyses are bounding for the power uprate.

10.1.3 Internal Flooding from an HELB

As stated in Section 10.1, plant operations at the EPU level will have an insignificant impact on the mass and energy release rates following an HELB. With regard to internal flooding resulting from an HELB, the licensee performed evaluations and stated that the internal flooding level is not changed due to the EPU.

Based on its review of the licensee's rationale and evaluation, the NRC staff finds that BSEP operations at the proposed EPU will have no impact on internal flooding resulting from an HELB.

10.2 Moderate Energy Line Breaks

The licensee stated that a moderate energy line break analysis (MELB) is not specifically required for the EPU by ELTR1. Therefore, MELB is not performed for the EPU at the BSEP. The NRC staff agrees with this conclusion and finds this acceptable.

10.3 Equipment Qualification

10.3.1 Electrical Equipment

10.3.1.1 Inside Containment

The licensee evaluated the equipment qualification for safety-related electrical equipment located inside the containment based on main steam line break and LOCA conditions. The licensee states that they will evaluate the temperature increase due to EPU through the EQ temperature monitoring program, which tracks such information for equipment aging considerations. The licensee's EQ review for the EPU conditions identified some equipment located within the containment that could potentially be affected by the higher radiation levels. The licensee stated that the qualification of this potential effect on equipment will be resolved by re-analysis, by refined radiation calculations, by reducing qualified life, by adding new equipment, or by replacing the existing equipment with qualified equipment. The NRC staff was concerned about the status of the licensee's analysis of the impact of EPU on equipment qualification and requested the schedule for completing necessary changes (e.g., qualification package revisions, equipment replacement, etc.) resulting from the EPU. By letter dated December 17, 2001, the licensee responded that revisions to the Qualification Data Packages (QDPs) to reflect EPU conditions are currently in progress. By letter dated March 22, 2002, the licensee stated that revision to QDPs to reflect EPU conditions have been completed and reviewed. No physical modifications to plant equipment were required to support the EPU.

Based on this, the NRC staff concludes that the plant satisfies the requirements of 10 CFR 50.49 at the EPU condition.

10.3.1.2 Outside Containment

The licensee evaluated EQ for safety-related electrical equipment located outside the containment based on a main steam line break in the pipe tunnel or other HELBs, whichever is limiting for each plant area. The accident temperature, pressure and humidity conditions resulting from a LOCA or HELB do not change with the power level. The licensee’s EQ review for the EPU conditions identified some equipment located outside the containment that could potentially be affected by the higher radiation levels. The licensee stated that the qualification of this potential effect on equipment will be resolved by re-analysis, by refined radiation calculations, by reducing qualified life, by adding new equipment, or by replacing the existing equipment with the qualified equipment. The NRC staff was concerned about the status of the licensee's analysis of the impact of EPU on equipment qualification and requested the schedule for completing necessary changes (e.g., qualification package revisions, equipment replacement, etc.) resulting from the EPU. By letter dated December 17, 2001 the licensee responded that revisions to the QDPs to reflect EPU conditions are currently in progress. By letter dated March 22, 2002, the licensee stated that revisions to QDPs to reflect EPU conditions have been completed and reviewed. No physical modifications to plant equipment were required to support the EPU. Based on this, the NRC staff concludes that the plant satisfies the requirements of 10 CFR 50.49 at the EPU condition.

10.3.2 Mechanical Equipment With Non-Metallic Components

Plant operation at the proposed EPU level increases the normal process temperature. The licensee stated that mechanical equipment with non-metallic components were evaluated and were determined to be acceptable for the environmental conditions associated with the EPU. Also, the normal and accident radiation levels increase slightly. The licensee performed an evaluation and identified some equipment that would potentially be affected by the slight increases in radiation levels. The licensee stated that the qualification of such equipment will be resolved by re-analysis; by refined radiation calculations (location specific); by slightly reducing the qualified life of the equipment; by adding new equipment; or by replacing the existing equipment with qualified equipment.

Based on the review of the licensee's rationale, the NRC staff finds the licensee's approach to qualification of mechanical equipment with non-metallic components for plant operations at the proposed EPU level acceptable.

10.3.3 Mechanical Components Design Qualification

This is evaluated in section 10.1.2.

10.4 <u>Required Testing</u>

10.4.1 Recirculation Pump Testing

Evaluation included in Section 10.4.4

10.4.2 10 CFR 50 Appendix J Testing

Evaluation included in Section 10.4.4

10.4.3 Main Steam Line and Feedwater Piping Flow-Induced Vibration Testing

Evaluation included in Section 10.4.4

10.4.4 Evaluation and Conclusion

The review included verifying that the licensee has provided sufficient information to demonstrate conformance with the NRC-approved review methodology for power uprate testing given in GE Licensing Topical Report NEDC-32424P-A.

10.4.4.1 Generic Test Guidelines for GE BWR EPU

Section 5.11.9 of GE Licensing Topical Report NEDC-32424P-A, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate” (GE proprietary), dated February 1999, provides the general guidelines for EPU testing and has been accepted by the NRC as the review basis for EPU amendment requests. Per the report, a testing plan will be included in the EPU licensing application which will include the pre-operational tests for systems or components which have revised performance requirements.

Guidelines to be applied during the approach to and demonstration of uprated operating conditions are provided in NEDC-32424P-A, Section L.2, “Guidelines for Uprate Testing.” GE Topical Report NEDC-33039P, “Safety Analysis Report For Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate,” submitted with the licensee’s application, provides additional information relative to power uprate testing.

10.4.4.2 Testing Plan

The licensee will conduct a limited subset of the original startup tests at the time of implementation of the EPU. The tests will be conducted in accordance with the NRC-approved generic EPU guidelines of NEDC-32424P-A to demonstrate the capability of plant systems to perform their design functions under uprated conditions.

The tests will be done in accordance with a site-specific test procedure developed by the licensee and will follow established controls and procedures that have been revised to reflect the uprated conditions. The tests consist essentially of steady state, baseline testing between 90 and 100 percent of currently licensed power. Several sets of data will be obtained between 100 and 115 percent current power, with no greater than a 5 percent power increment between data sets. A final set of data will also be obtained at the uprated (115%) power level. The licensee’s power increase test plan is given in Section 10.4 (“Required Testing”) of NEDC-33039P, which provides:

a. Surveillance testing will be performed on the instrumentation that requires re-calibration for the EPU, in addition to the testing performed according to the plant TS schedule.

b. During the power ascension in which the current RTP will be exceeded, steady-state data will be taken starting at 90% of the current RTP up to the EPU RTP so that system performance parameters can be projected throughout the EPU power ascension.

c. Power increases beyond the previous rating will be made along an established flow control/rod line in increments of less than or equal to 5% power. Steady-state operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows, and vibrations will be evaluated from each measurement point prior to the next power increment.

d. Control system tests will be performed for the feedwater/reactor water level controls and pressure controls. These operational tests will be made at the appropriate plant conditions for that test and at each power increment above the previous rated power condition, to show acceptable adjustments and operational capability.

e. A test specification will be prepared to identify the EPU tests, the associated acceptance criteria and appropriate test conditions. All testing will be done in accordance with written procedures as required by 10 CFR 50, Appendix B, Criterion XI.

f. Original performance criteria and modified performance criteria updated since the initial test program are utilized for supporting EPU power ascension testing.

g. Vibration testing of the main steam and feedwater piping will be performed.

BSEP does not intend to perform the large transient testing included in the NRC-approved topical report. The NRC staff's evaluation of the licensee's rationale for not performing this testing is discussed in Section 10.4.4.3.D below.

10.4.4.3 Large Transient Tests

A. Background

To achieve an EPU, a licensee makes several major modifications to the plant. However, most of the major modifications are made to non-safety-related secondary plant systems such as the main turbine, generator, and feedwater system. As outlined above, testing is done in accordance with technical specification surveillance requirements on instrumentation that is re-calibrated for EPU conditions. A licensee's power ascension test plan includes hold points for testing and data collection. Steady-state data will be taken at points from 90% up to100% of the pre-uprated thermal power, so that system performance parameters can be projected for uprate power before the pre-uprated power rating is exceeded. Power increases will be made along an established flow control/rod line in increments of 5% power or less. Steady-state operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows and vibration will be evaluated from each measurement point, prior to the next power increment. Radiation measurements will be made at selected power levels to ensure the protection of personnel.

The proposed EPU results in an increase in steam and feedwater flow rates with no increase in reactor dome pressure. It also results in a small operating pressure/temperature decrease at the turbine inlet and increased loading of certain electrical equipment.

B. Systems/Components with Revised Performance Requirements

Guidelines in NEDC-32424P-A specify that pre-operational tests will be performed for systems or components which have revised performance requirements. These tests will occur during ascension to extended power uprate conditions. The performance tests and associated acceptance criteria are based on BSEP original startup test specifications and previous GE BWR power uprate test programs.

CP&L proposes not to perform the large transient tests in NEDC-32424P-A for MSIV closure and generator load rejection. NEDC-32424P-A includes recommendations to perform the MSIV closure test for power uprates greater than 10 percent above any previously recorded MSIV closure transient data and the generator load rejection test for power uprates greater than 15 percent above any previously recorded generator load rejection transient data. In a letter dated December 20, 2001, in response to an NRC RAI on this topic, CP&L provided justification for not performing these tests. In addition, in a letter of December 21, 2001, GE submitted a generic response justification for not performing the large transient tests for its Constant Pressure Power Uprate application, which is currently under NRC staff review.

C. Discussion

In evaluating CP&L's justification to not perform the large transient tests, the NRC staff considered the modifications, if any, made to the plant for an EPU as they relate to the tests; component and system level testing that will be performed either as part of the CP&L power ascension and test plan or to meet TS surveillance requirements; past experience at BSEP and other plants; and the importance of the additional information that could be obtained from performing the tests with respect to plant analyses.

C.1 Transient Tests and Modifications

Large transient testing is normally performed on new plants because no experience exists to confirm a plant's operation and response to events. These tests are not normally performed for plant modifications after initial startup because plant quality assurance and maintenance programs have provided component and system level post-modification testing plus extensive experience with general behavior of unmodified equipment. Large transient testing may be needed for major modifications to a plant to confirm that the modifications were correctly implemented and effective, but such testing should only be required if considered necessary to demonstrate safe operation of the plant.

C.2 Experience

CP&L provided information on testing and events that occurred at previously uprated BWR plants – Hatch Units 1 & 2 and and Leibstadt (i.e., KKL) – and stated that the testing and responses to unplanned transients at these plants showed that plant response was consistently within expected parameters. In addressing these previous power uprates, CP&L noted that the

EPU application for Hatch was granted by the NRC without requiring large transient testing. CP&L also stated that Hatch Units 1 and 2 are similar in design and size to BSEP such that the response to transients would be very similar to Hatch. An unplanned event at Hatch Unit 2 resulted in a generator load reject from 98% of uprated power with no anomalies in the plant's response to the event (Southern Nuclear's Licensee Event Report (LER) 1999-005). Further, Hatch Unit 1 had one turbine trip and one generator load reject subsequent to its EPU (LERs 2000-004 and 2001-002) in which the Hatch primary safety systems functioned as expected. In all the Hatch events, no plant responses indicated that the analytical models used were not capable of modeling plant behavior under EPU conditions. In the KKL EPU, power was raised in steps from the initial 3138 MWt (104.2% of OLTP) to 3515 MWt (116.7% OLTP) and uprate testing performed at 3327 MWt (110.5% OLTP), 3420 MWt (113.5% OLTP), and 3515 MWt (116.7% OLTP). The tests involved turbine trips at 110.5% OLTP and 113.5% OLTP, and generator load reject at 104.2% OLTP. The results from these large transient tests demonstrated that the responses were consistent with the uprate licensing analyses and predicted responses. No new plant behavior was observed in these tests and events.

As additional support to CP&L's argument for not performing large transient tests, NEDC-32424P-A states that "the operating history of the plants has shown previous transient events from full power to be within expected peak limiting values." This conclusion was supported by BSEP LER-2000-002-00 on a load shed at BSEP Unit 2 on September 22, 2000, with no complications. Specifically, Unit 2 "was operating at 100% rated thermal power when the Unit 2 phase of the Main Power Transformer experienced a fault resulting in a generator load reject and subsequent turbine trip and reactor scram." In a letter dated December 20, 2001, CP&L responded to an NRC RAI asking CP&L to provide justification for not performing the large transient tests. The CP&L response included a discussion of the September 22, 2000, event and stated that "no anomalies were seen in the plant's response to this event . . . this event satisfies the ELTR-1 requirement for previously recorded Generator Load Rejection transient data within 15% of the BSEP EPU licensed power level of 2923 MWt."

D. Staff Evaluation

The NRC staff agrees that transient tests only challenge a limited set of systems and components and that other testing and/or events can demonstrate adequate performance for the equipment modified as part of the EPU. Specifically, the list of system and component tests required by the TS are sufficient to demonstrate the system and/or component initiation setpoint and performance characteristics. Further, the importance of the information that might be gained from the transient tests was also considered in light of experience with EPUs at BWR plants and the BSEP load shed event. Although all BWR designs are not identical, the NRC staff considers such experience useful, because it indicates how well the analyses can predict the impact of the power uprate and hardware modifications on equipment response during events. Specifically, this general and plant-specific experience indicates that observed responses do not differ significantly from predictions. The NRC staff also previously reviewed information provided by AmerGen/Exelon for Dresden and Quad Cities in which no significant anomalies related to plant safety were identified by the tests and/or actual events.

The results of the tests under consideration would not be directly comparable to the results of the safety analyses used for licensing plants or granting amendments. In performing safety analyses, licensees use bounding assumptions such as assuming the failure of the most limiting component (e.g., single failure). In addition, when performing licensing analyses, licensees do not rely on nonsafety-related equipment or anticipatory trips for mitigation. In performing the tests under consideration, the licensee would not be expected to disable the limiting component, non-safety equipment, or anticipatory trips to mimic the safety analysis cases. Therefore, the results of the tests would be much less limiting than those of the safety analyses. Furthermore, because of the availability of the additional equipment (i.e., non-safety-related equipment and anticipatory trips), the test case scenarios would be significantly different (i.e., follow different success paths) from the corresponding safety analyses. Thus, successful large transient testing would not confirm the adequacy of the existing analyses.

The NRC staff also does not consider the information that could be obtained from the large transient tests to be necessary for validation of the analytical codes. The basis for this conclusion is that these codes have been validated using test data obtained from numerous test facilities and operational experience in BWRs.

The NRC staff's review identified a question as to whether the increased steam flow resulting from the EPU could cause the MSIVs to close more rapidly. The CP&L submittal for the BSEP EPU notes that MSIVs are part of the reactor coolant pressure boundary, perform the safety function of steamline isolation during abnormal events, and must be able to close within a specified time range at all design and operating conditions. CP&L indicates that a GE generic evaluation (which includes a 24% steam flow increase) bounds the effect of the proposed power uprate for BSEP with respect to the MSIVs. CP&L states that the increase in steam flow for the power uprate conditions requested for BSEP will assist in MSIV closure. The NRC staff questioned whether the increased steam flow might cause the MSIVs to close faster than the 3-second minimum closure time assumed by CP&L. More rapid closure of the MSIVs could result in pressure and reactivity transients more significant than predicted by the analysis. The NRC staff presented this concern to GE and later to CP&L on February 7 and 14, 2002, respectively. In response, CP&L provided an MSIV design calculation, an original MSIV startup test procedure with closure time data, and an MSIV operational description from the vendor manual.

The MSIVs at BSEP are 24x20x24 inch Rockwell-Edward globe valves that are installed such that flow will assist in their closure and are equipped with an air cylinder operator and springs to open and close the valves. A hydraulic cylinder with two pressure-compensated flow control valves and check valves is incorporated to control the opening and closing speeds of each MSIV under various system conditions. The flow control valves are arranged to allow the transfer of fluid from either side of the hydraulic cylinder during valve operation in a controlled manner such that steam flow does not affect MSIV closing speed. CP&L reported that the MSIV closure times are confirmed to be between 3 and 5 seconds under static conditions during each cold shutdown if a full stroke exercise has not been performed within the previous three months. The startup test procedure provided by CP&L reveals that the MSIV closure times under 10.2 million pounds per hour (Mlb/hr) of steam flow were approximately 4 seconds. These recorded MSIV closure times under significant steam flow conditions reveal the success of the design arrangement in minimizing the effect of steam flow on MSIV performance. CP&L also noted that unacceptable MSIV performance has not been observed based on operating experience with MSIV closure under steam flow conditions. The design of the MSIVs to control closing speed and the absence of an identifiable effect on MSIV closure time from steam flow during plant tests and operations support a determination that the increase of the steam flow rate to 12.781 Mlb/hr under the power uprate conditions will not significantly impact MSIV performance.

Based on review of CP&L's submittal for the proposed power uprate, the CP&L submittals in response to NRC staff questions, and the additional information provided by CP&L on MSIV design and operation, the NRC staff agrees that the increased steam flow conditions associated with the proposed power uprate are expected to result in acceptable MSIV closure times.

10.4.4.4 Conclusions

GE Nuclear Energy Topical Report NEDC-32424P-A, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate,” (ELTR-1), February 1999, has been accepted by the NRC as the review basis for EPU amendment requests. GE Licensing Topical Report NEDC-33004P, “Constant Pressure Power Uprate,” Revision 1 (Proprietary), dated July 2001, submitted to the NRC staff for review also includes generic guidelines for testing but has eliminated the recommendation in NEDC-32424P-A to perform large transient tests. The NRC staff has previously accepted not performing these tests on a plant specific basis for the Dresden and Quad Cities plants. In a letter dated December 20, 2001, CP&L’s response to an NRC staff RAI provided justification for not performing these tests.

The NRC staff finds that the performance of numerous component, system, and other testing, in combination with the evaluation of the systems and components and operating experience discussed above, is sufficient to satisfactorily demonstrate successful plant modifications and performance. The NRC staff also finds that information obtained from the MSIV closure and generator load rejection tests could be useful to confirm plant performance, adjust plant control systems, and enhance training material. However, the NRC staff does not consider such benefits to be sufficient to justify the challenges to the plant and its equipment; the potential risk, although small, associated with performing these tests (i.e., the risk due to potential random equipment failures during the test); and the additional burden that would be imposed on the licensee. The NRC staff also concludes that these tests do not provide new and significant information that would confirm the adequacy of the safety analyses and that they are not required for Code validation.

The CP&L test plan follows the guidelines of NEDC-32424P-A and the NRC staff position regarding individual EPU amendment requests, except for the issue of large transient tests. The NRC staff finds that the applicant’s EPU testing program is consistent with the requirements of 10 CFR 50, Appendix B, Criterion XI, “Test Control” and the recommendations of NRC-approved GE topical report NEDC-32424P-A, and is therefore acceptable. In addition, based on the above evaluation, the NRC staff finds it acceptable to not perform the large transient tests at BSEP.

10.5 <u>Risk Implications</u>

To evaluate the risk impact at BSEP from the proposed EPU, the licensee assessed its plant-specific probabilistic safety assessment (PSA) for internal events and its individual plant examination of external events (IPEEE). The NRC staff reviewed the information provided in the licensee’s submittal of August 9, 2001, specifically, the PSA section of Enclosure 3 of the licensee’s submittal, and the licensee’s letters to the NRC dated November 30, 2001 (which included as an enclosure its EPU risk evaluation), February 4, 2002, February 21, 2002, and March 5, 2002.

10.5.1 Background

The effects of the EPU at BSEP were evaluated by the licensee, who made the overall conclusion that the EPU is expected to result in a very small increase in core damage frequency (CDF) and a small increase in the large early release frequency (LERF), based on its internal events evaluations. When considering the licensee’s proposed modification to the SLC system to support the transition to the GE14 fuel design, which is necessary to achieve the full EPU, the overall plant risk will actually be reduced by about 9 percent in CDF and 28 percent in LERF.

10.5.2 Evaluation

This section includes the evaluation of NEDC-22029P, Section 10.5, “Individual Plant Evaluation.”

The NRC staff reviewed the information provided in the licensee’s original submittal, specifically, the PSA section of Enclosure 3 to its August 9, 2001, submittal as amplified by the licensee’s responses to the NRC staff’s RAIs. The NRC staff used the guidance provided in RG 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” to focus the review of this non-risk-informed submittal. The NRC staff’s evaluation of the licensee’s submittal focused on the capability of the licensee’s PSA and other risk evaluations (e.g., for external events) to analyze the risks stemming from both the current, pre-EPU plant operations and the proposed post-EPU conditions. The NRC staff’s evaluation did not involve an in-depth review of the licensee’s PSA, but rather focused on whether the EPU would raise questions regarding the licensee’s ability to continue to maintain adequate protection by meeting the deterministic requirements and regulations. This evaluation included a review of the licensee’s discussions of EPU impacts on CDF and LERF due to internal events, external events, and shutdown operations. The evaluation also addressed the quality of the BSEP PSA, commensurate with its use in the licensee’s and NRC staff’s decision-making processes.

10.5.2.1 Internal Events

The NRC safety evaluation report on the BSEP individual plant examination (IPE) was issued in 1995 and concluded, based on the NRC staff’s “Step 1" review, that the licensee had met the intent of GL 88-20, “Individual Plant Examination for Severe Accident Vulnerabilities.” The licensee has updated the BSEP internal events PSA several times since the NRC staff review relative to GL 88-20 to reflect the current plant configuration and to reflect the accumulation of additional plant operating history and component failure data.

The licensee evaluated the changes due to EPU implementation for its potential impact on the BSEP internal events PSA in the following key areas: initiating event frequency, component reliability, system success criteria, and operator response. Each of these areas is specifically addressed in the following subsections, with the NRC staff’s evaluation findings, followed by a description of the overall impacts due to the EPU on the internal events CDF and LERF.

10.5.2.1.1 Initiating Event Frequency

The licensee stated in its submittal that the EPU would not create any new initiating events or increase the frequency of any existing initiating events. However, the licensee will be making a number of changes to the BOP equipment in support of the EPU. The licensee evaluated the capabilities of the systems and components that will need to run at higher capacities and the licensee stated that, as needed, components were being replaced or modified to improve their capability. Examples of the systems and components that the licensee has proposed to replace or modify include:

- Replacing or rewinding the main transformer to obtain additional capacity.
- Rewinding the main turbine generator to obtain additional capacity.
- Modifying the main generator hydrogen cooling and stator cooling system.
- Replacing the high pressure turbine rotor.
- Replacing the reactor feedwater pump turbines with higher horsepower turbines.
- Replacing the condensate and condensate booster pumps and motors with upgraded units that have sufficient margin.
- Replacing feedwater heaters.
- Installing a supplemental condensate cooling system to provide additional cooling capacity during warmer months.
- Replacing condensate filter demineralizers with longer filter elements.
- Modifying the moisture separator/reheater and moisture separator/reheater relief valves.
- Modifying the SLC by changing pentaborate to a higher enrichment.
- Modifying the isophase bus duct cooling system to provide additional cooling capacity.
- Modifying the LOCA voltage load shed to maintain minimum switchyard voltage.
- Modifying the power system stabilizer or static exciter and the turbine generator Out-Of-Step relaying to alleviate potential grid stability concerns caused by the increased electrical output.

Due to the numerous BOP modifications, there is the potential in the near-term for equipment "break-in" failures. The licensee performed a sensitivity calculation (Sensitivity #1) in which the frequency of the turbine trip initiating event was increased by 10 percent. This increase in the frequency of turbine trips was used to represent the short-term impact from the break-in failure stage that might be associated with the numerous BOP changes, especially in those systems related to the power conversion system, that would be implemented in support of the EPU. This sensitivity case indicated that a 10-percent increase in the turbine trip initiating event frequency would result in a 6.3 percent increase in the base CDF, from a pre-EPU CDF of 2.55E-5/year to a post-EPU CDF of 2.71E-5/year, an increase of 1.6E-6/year. This increased initiating event frequency also resulted in a 13.3 percent increase in the base LERF, from a pre-EPU LERF of 4.27E-6/year to a post-EPU LERF of 4.84E-6/year, an increase of 5.7E-7/year.

The NRC staff finds that it is reasonable to conclude that the initiating event frequencies will not change, as long as the operating ranges or limits of the equipment are not exceeded. This NRC staff finding is based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Further, based on the licensee's sensitivity calculation, any short-term risk impact from break-in failures due to the numerous

BOP equipment changes is expected to be small. Finally, the NRC staff notes that if there are any changes observed in the future in initiating event frequencies, these changes will be identified and tracked under the plant's existing performance monitoring programs and processes and will be reflected in future updates of the PSA based on plant actual operating experience.

The NRC staff has not identified any issues associated with the licensee's evaluation of initiating event frequencies that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the evaluation of initiating event frequencies associated with the BSEP internal events PSA that would warrant denial of this license amendment, and the expectation is that there will be no change in initiating event frequencies as a result of the EPU.

10.5.2.1.2 Component Reliability

The licensee concluded in its submittal that the EPU would not significantly impact the reliability of equipment. This conclusion is supported by the fact that no safety-related equipment is expected to be operated beyond its design limits or operating ranges as a result of the EPU. However, as identified in Section 10.5.2.1.1 of this SE, the licensee did identify a number of modifications that will be installed on certain equipment to extend the ratings of the equipment to bound the EPU conditions.

In response to an NRC staff RAI, the licensee stated that as part of its EPU evaluation, it determined that parameters for some non-safety, BOP equipment may exceed their original design values. The flow velocities in the third, fourth, and fifth feedwater heaters may marginally exceed the original design values and Heat Exchanger Institute recommendations and the motors for the condensate and condensate booster pumps may encroach upon their nameplate ratings. In addition, the licensee will periodically monitor the material condition of the feedwater heaters and trend the available margins of the pump motors and make any appropriate equipment modifications to ensure component reliability. Thus, for both of these conditions, the licensee expects no increase in plant risk.

In addition, the licensee is making a modification that will enable selected non-safety-related motors to be automatically load shed on a main generator lockout signal. In response to an NRC staff RAI regarding this modification, the licensee indicated that this modification would not create a new initiating event or increase the frequency of any existing initiating event since the load shedding actions occur after a unit trip or LOCA. However, it was recognized that if the switches were misaligned during heavy grid load conditions, a trip-induced loss of offsite power could occur. Further, under this load shed logic scheme, certain non-safety-related equipment (e.g., the standby condensate and condensate booster pumps) that are currently credited in the BSEP internal events PSA model may not be readily available. The licensee evaluated both of these potential consequences of the modification and determined that the risk impact was negligible in both cases.

The NRC staff finds that it is reasonable to conclude that equipment reliability will not change significantly, as long as the operating ranges or limits of the equipment are not exceeded. This NRC staff finding is based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Further, as previously discussed in Section 10.5.2.1.1 of this SE, any short-term risk impact of the numerous BOP equipment changes, due to break-in failures, is expected to be small. Finally, the NRC staff notes that the licensee's component monitoring programs are being relied upon to maintain the current reliability of the equipment, especially for those parameters identified above that may exceed their original design values. The NRC staff finds it reasonable to conclude that there will not be a substantial impact on the reliability of these components, as long as the component monitoring programs are properly implemented and appropriate actions, including equipment modifications and/or replacement, are taken by the licensee based on the collected monitoring/trending data.

The NRC staff has not identified any issues associated with licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the component reliabilities/failure rates modeled in the BSEP internal events PSA that would warrant denial of this license amendment, and the expectation is that there will be no change in component reliability as a result of the EPU.

10.5.2.1.3 Success Criteria

The licensee evaluated the system success criteria of the BSEP internal events PSA, specifically considering the affects of the increased boil-off rate, the increased heat load to the suppression pool, the increased blowdown loads, and the increased containment pressures and temperatures. However, the licensee further stated that the changes in these parameters due to the EPU are generally small compared with the capability of the systems credited in the PSA. The licensee performed thermal-hydraulic calculations using the modular accident analysis program (MAAP) computer code for the proposed EPU conditions. Based on the BSEP EPU MAAP runs, the licensee concluded that no adverse changes were identified in the system success criteria for the BSEP internal events PSA, demonstrating the significant margins associated with the systems.

The licensee noted that the current BSEP internal events PSA credits the fire protection system water and service water crosstie for level-power control during ATWS scenarios. However, as part of the EPU evaluations, the licensee determined that there were no detailed analyses to support the assumed capability of these systems under the ATWS scenarios. Therefore, as part of the EPU evaluations, the licensee performed a sensitivity calculation (Sensitivity #4) in which it removed the credit for these systems. The results of this sensitivity calculation indicate that there are no changes from the base EPU model, which indicates that the crediting, or not crediting, of these systems has a negligible impact on the PSA and does not impact the EPU evaluation.

In addition, the NRC staff noted that the licensee's EPU evaluation was performed only for BSEP Unit 2, with the assumption that the two units are essentially identical. However, the NRC staff was aware that for at least one area, the units are considerably different. The turbine bypass valve (TBV) capacity at Unit 2 is significantly greater than that at Unit 1. The TBV capacity relative to the pre-EPU full power level at Unit 2 is about 80 percent and at Unit 1 is about 24 percent. The TBV capacity relative to the post-EPU full power level at Unit 2 is about 70 percent and at Unit 1 is about 21 percent. The NRC staff pursued, through an RAI, the potential implications of the proposed EPU on the Unit 1 TBV capacity and its associated success criteria of 4-out-of-4 TBVs opening to allow steam dumping to the condenser. The licensee responded that while a small reduction in the relative steam bypass capacity for each unit would occur as indicated by the above values, the pressure control system would remain able to perform its design function under EPU conditions and that this small relative reduction in TBV capacity would not impact the success criteria in the BSEP Unit 1 PSA. The licensee also indicated that there were no other significant differences between the two units that could impact the success criteria in the BSEP internal events PSA.

Finally, the licensee plans to implement a modification to the SLC system that would change its success criteria from 2-out-of-2 SLC pumps and squib valves to 1 out of 2 SLC pumps and squib valves. Thus, this modification would result in a risk reduction at the BSEP. As part of the EPU evaluations, the licensee performed a sensitivity calculation (Sensitivity #3) in which it modified the SLC system model to reflect this change in success criteria. The results of this evaluation indicate a risk reduction of about 9 percent in CDF and 28 percent in LERF.

The NRC staff finds that it is reasonable to expect that the system success criteria will not change due to the EPU. The NRC staff has not identified any issues associated with licensee's evaluation of success criteria that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the success criteria associated with the BSEP internal events PSA that would warrant denial of this license amendment, and the expectation is that there will be no change in system success criteria as a result of the EPU.

10.5.2.1.4 Operator Response

The licensee employed a compilation of commonly used methods in its human reliability analysis (HRA). For example, the proceduralized post-initiator operator errors were quantified using two complementary approaches: (1) the human cognitive reliability (HCR) correlation developed by EPRI, which incorporates data from the operator reliability experiments (ORE) that are described in EPRI reports NP-6560L, "A Human Reliability Analysis Approach Using Measurements for Individual Plant Examinations," and TR-100259, "An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment," and (2) the cause-based methodology developed by EPRI and also documented in EPRI topical report TR-100259. The HEP is derived for a specific operator action by summing the higher of the values derived by these two approaches with the calculated execution failure probability.

The licensee stated in its submittal that the performance shaping factor that is principally influenced by the EPU is the time available within which to detect, diagnose, and perform certain required actions. The licensee further identified and reviewed operator actions that had a Fussell-Vesely (F-V) importance measure that was greater than 5.0E-3 or that had an available operator response time that was less than 30 minutes. The licensee also identified only four operator actions that required their human error probabilities (HEPs) to be recalculated due to changes in operator response times caused by the EPU increase in decay heat level. All four of these operator actions are related to RPV water level control during an ATWS. Even though the HEPs were changed for these operator actions to reflect the reduction in the time available to perform these actions, the impact on the PSA results were relatively small. The increased HEPs result in only about a 1.6 percent increase in the base CDF, from a pre-EPU CDF of 2.55E-5/year to a post-EPU CDF of 2.59E-5/year, an increase of 4.0E-7/year. Likewise, the increased HEPs result in only a 4.5 percent increase in the base LERF, from a pre-EPU LERF of 4.27E-6/year to a post-EPU LERF of 4.46E-6/year, an increase of 1.9E-7/year.

In response to an NRC staff RAI, the licensee identified a total of twenty-six operator actions that exceeded their F-V importance measure and another sixteen operator actions that exceeded their available response time measure. In reviewing these operator actions, the NRC staff notes that many of the currently calculated HEP values are based on a conservative estimate of the available time that bounds (i.e., is less than) the actually calculated time available for both pre-EPU and post-EPU conditions. This is the situation for many of the operator actions that are typically identified as being impacted by the EPU, including: initiating emergency RPV depressurization, inhibiting the actuation of the ADS, initiating suppression pool cooling, initiating a manual scram, initiating the SLC system, and initiating a number of RPV injection sources.

The licensee has used a compilation of HRA methodologies to calculate the operator action HEPs for the pre-EPU and post-EPU plant conditions. The differing HEP values for the same operator action reflect the reduction in available time to diagnose and perform these actions due to the increased decay heat levels caused by the EPU. These HRA methodologies, which are commonly used by the industry in performing HRAs for PSAs, have not been formally reviewed and approved by the NRC. The NRC staff recognizes that these methodologies may involve large uncertainties and that the absolute values cannot be used as the sole basis for determining the acceptability of a license application. However, the evaluations can provide insights into the relative importance, or change in importance, of selected operator actions and can be used to focus the NRC staff review of the license application. For those operator actions in which the HEPs were recalculated, the NRC staff finds that the licensee’s HRA application is consistent with the HRA methodologies identified above and that the assumed increases in the HEP values reasonably reflect the reductions in the times available for operators to perform the necessary actions under the EPU conditions. However, the NRC staff also finds that most of the HEPs for operator actions that would be impacted by the EPU are bounded by the conservative times estimated in the licensee’s current analysis.

The NRC staff would have pursued further the manner in which the licensee calculates the change in risk due to the EPU if this had been a risk-informed license application. The licensee’s approach does not reflect the actual change in risk due to the EPU since many of the potentially impacted operator actions used a conservative operator response time that bounds the realistic times available under both pre-EPU and post-EPU plant conditions. If more realistic operator response times were used in the current, pre-EPU analysis, the calculated change in risk values may have been determined to be greater than cited, though the base risk values for both the pre-EPU and post-EPU plant conditions would have been less than cited. The NRC staff believes that this issue would not significantly alter the overall results or conclusions for this license amendment, as the current, pre-EPU base CDF is 2.55E-5/year and the current, pre-EPU base LERF value is 4.27E-6/year. Safety insights from these base risk values do not raise the concern of adequate protection. Therefore, the NRC staff concludes that there are no issues with the HRA evaluation for EPU that would warrant denial of this license amendment.

10.5.2.1.5 Summary of Internal Events Evaluation Results

As stated in the preceding subsections, the licensee indicated that no impacts are expected due to the EPU for initiating event frequencies, component reliability, or success criteria, but potential impacts of the EPU were identified for selected operator actions due to the decrease in available operator response times. Based on the licensee’s evaluation, the implementation of the EPU increases the BSEP internal events PSA CDF from the pre-EPU base value of 2.55E-5/year to the post-EPU base value of 2.59E-5/year, an increase of 4.0E-7/year or 1.6 percent.

The Level 2 analysis calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. The slight changes in accident progression timing and decay heat load are stated by the licensee to have negligible or only minor impacts on the containment safety functions, such as containment isolation, ex-vessel debris coolability, and ultimate containment strength. The EPU change in power represents a relatively small change to the containment failure probability under severe accident conditions. Carrying the changes to the Level 1 analysis (i.e., core damage scenarios) as an input to the Level 2 analysis, the licensee states that the EPU increases the BSEP internal events PSA LERF from the pre-EPU base value of 4.27E-6/year to the post-EPU base value of 4.46E-6/year, an increase of 1.9E-7/year or 4.5 percent.

In response to an NRC staff RAI, the licensee provided a list of the risk contributors, by initiating event, to CDF and LERF for both the pre-EPU and post-EPU evaluations. The dominant contributors to CDF are identified by initiating event as: turbine trip (about 37 percent pre-EPU and 38 percent post-EPU), loss of offsite power (about 31 percent pre-EPU and 30 percent post-EPU), and loss of 125V dc panel 2B2 (about 8 percent pre-EPU and post-EPU). No other initiating event contributes more than 4 percent to CDF. The dominant contributor to LERF is from the turbine trip initiating event (about 75 percent pre-EPU and 76 percent post-EPU). No other initiating event contributes more than 4 percent to LERF. Although some fractional/percentage contributions are slightly reduced, their absolute values remain the same or may even increase slightly. The reduced fractional/percentage contributions occur to offset the larger increases of other contributors, such as from the turbine trip initiating event. This list shows that the dominant contributors do not change as a result of the EPU, even though their individual contributions may change slightly.

In addition to its base evaluation, the licensee performed a number of sensitivity calculations using different assumed conditions to support its decision-making process. Sensitivity #1 addressed the potential for the near-term break-in failures resulting from the numerous changes being made as part of the EPU to various BOP equipment. This calculation, which was previously discussed in Section 10.5.2.1.1 of this SE, increased the turbine trip initiating event frequency by 10 percent. Sensitivity #2 addressed the potential for an increase in the probability of failure of the operators' ability to control RPV level, resulting in the tripping of the feedwater pumps on high level. This calculation involved the doubling of the HEP associated with level control. Sensitivity #3 addressed the potential improvement that could be achieved by implementing modifications to the SLC system that would allow a single SLC train to be considered a success in the model (i.e., would change the SLC system success criteria from 2 out of 2 pumps and squib valves to 1 out of 2 pumps and squib valves). For this calculation, model changes were made to reflect the revised success criteria. Sensitivity #4 addressed the potential that the alternate RPV injection capability using fire water or service water might not be adequate or that there might not be sufficient time to align these alternate sources. For this calculation, model changes were made to eliminate these sources of alternate RPV injection capability. Sensitivity #5 addressed the combined impacts from the three adverse sensitivity cases (i.e., Sensitivity #1, #2, and #4), without taking credit for the potential benefit from implementing the SLC system modifications. As such, this is the worst-case sensitivity calculation. Sensitivity #6 addressed the combined impacts from all the sensitivity cases (i.e., Sensitivity #1, #2, #3, and #4), including the credit for the beneficial impact that could be achieved by implementing the SLC system modifications.

Sensitivity #5 (i.e., the worst-case combined sensitivity case without credit for the SLC system modifications) results indicate that the assumed conditions would result in about a 6.9 percent increase in the base CDF, from a pre-EPU CDF of 2.55E-5/year to a post-EPU CDF of 2.73E-5/year, an increase of 1.8E-6/year, and also result in a 13.3 percent increase in the base LERF, from a pre-EPU LERF of 4.27E-6/year to a post-EPU LERF of 4.84E-6/year, an increase of 5.7E-7/year. The increases in CDF and LERF are primarily due to the increase in the turbine trip initiating event frequency (i.e., Sensitivity # 1).

When the SLC system modification is implemented, the net risk impact of the EPU is a risk reduction, even when considering the adverse impacts of the other sensitivity cases. Thus, the safety improvement achieved by the SLC system modification actually outweighs the other analyzed adverse impacts. Based on Sensitivity #6 (i.e., the combined sensitivity case with credit for the SLC system modifications), the CDF is reduced by 4.8 percent to 2.43E-5/year and the LERF is reduced by 22.7 percent to 3.30E-6/year.

Even when considering the worst-case combined sensitivity case (Sensitivity #5), the NRC staff finds that the changes in CDF and LERF from internal events due to the proposed EPU are both small. Therefore, based on the reported analyses and results, the NRC staff concludes that the changes in CDF and LERF from internal events due to the proposed EPU are both within the acceptance guidelines provided in RG 1.174. Even so, as identified in Section 10.5.2.1.4 of this SE, the NRC staff has identified an issue with the manner in which the licensee calculates the change in risk. However, the NRC staff believes that this issue would not significantly alter the overall results or conclusions for this license amendment and would not affect the licensee's ability to maintain adequate protection by meeting the deterministic requirements and regulations. Therefore, the NRC staff concludes that there are no issues with the licensee's EPU evaluation of internal events that would warrant denial of the license amendment and the expectation is that the risk increase from internal events will at most be small as a result of the EPU.

10.5.2.2 External Events

The NRC safety evaluation report on the BSEP IPEEE was completed in 1998 and concluded, based on the NRC staff's "Step 1" review, that the licensee's process was capable of identifying the most likely severe accidents and severe accident vulnerabilities and therefore, that the licensee had met the intent of Supplement 4 to GL 88-20.

The licensee evaluated the changes due to EPU implementation for its potential impact on the external events analyses, specifically seismic events, fires, and high winds, floods, and other (HFO) external events. Each of these external events are individually addressed in the following subsections, followed by the NRC staff's findings regarding the impact of EPU on external events.

10.5.2.2.1 Seismic Events

For the IPEEE seismic analysis, BSEP is categorized as a 0.3g focused-scope plant per NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities." The licensee performed the BSEP seismic evaluation in its IPEEE using the EPRI seismic margins assessment (SMA) methodology described in EPRI NP-6041-SL, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin." Because the SMA is a deterministic evaluation process, the licensee did not quantify a seismic contribution to plant CDF.

The licensee did not identify any vulnerabilities in the safe shutdown components, systems, and structures in the two shutdown paths selected as part of its IPEEE SMA and the licensee stated that the SMA indicated that the overall high confidence of a low probability of failure (HCLPF) plant capacity was at least equal to the review level earthquake (RLE) value of 0.3g. This statement is based on the licensee having properly resolved a number of identified seismic outliers (i.e., identified as outliers either within the IPEEE or as part of the unresolved safety issue A-46 process). In response to an NRC staff RAI, the licensee stated that it had resolved all seismic outliers (i.e., IPEEE and A-46) in a manner to satisfy the IPEEE assumptions and conclusions.

Based on its qualitative evaluation, the licensee concluded that the EPU has little or no effect on the seismic qualifications of the systems, structures, and components, and that the BSEP IPEEE SMA results are unaffected by the EPU.

10.5.2.2.2 Fires

For the IPEEE, the licensee built upon a previous (i.e., 1987) fire probabilistic risk assessment (PRA) that had been reviewed by the NRC. The IPEEE fire analysis employed a combination of PRA and the EPRI fire-induced vulnerability evaluation (FIVE) methodologies. The overall approach, which the NRC staff's safety evaluation indicates is similar to other fire analysis techniques, implemented a graduated focus on the most important fire zones, using qualitative and quantitative screening criteria. The licensee estimated that the contribution to plant CDF from internal fires was approximately 3.4E-5/year. The dominant contributor to the fire-related CDF was from fires in the control room, which made up about 53 percent of the fire-related CDF. Based on the results of the internal events evaluation for EPU and an assessment of the BSEP IPEEE internal fires analyses, the licensee concluded that the effects on the calculated internal fires risk contribution would not be significant, which is indicated to be an increase in CDF of about 1 percent.

Based on the licensee's evaluation, the fire CDF would be increased by about 3.7E-7/year to an EPU fire CDF of about 3.5E-5/year. This base CDF and change in CDF are both well within the RG 1.174 acceptance guidelines, indicating a very small increase in risk. Even using the worst-case sensitivity results from the BSEP internal events PSA (i.e., Sensitivity #5), which estimated an increase in the internal events CDF of about 6.9 percent, the fire CDF results would still be within the RG 1.174 acceptance guidelines. Using the licensee's approach to calculating the EPU fire impact, the CDF would increase by about 4.6 percent, resulting in a base EPU fire CDF of about 3.6E-5/year and a change in fire CDF of about 1.6E-6/year. These results indicate at most only a small increase in risk from fires due to the EPU.

10.5.2.2.3 High Winds, Floods, and Other (HFO) External Events

The NRC staff SE on the IPEEE indicates that the licensee's approach for evaluating HFO external events is consistent with the progressive screening approach described in NUREG-1407. Extreme winds and flooding events were analyzed further using quantitative probabilistic calculations. Transportation and nearby facility accidents were also evaluated. The contribution to CDF from HFO external events is completely dominated by extreme winds, which was calculated to have a CDF contribution of about 4.0E-6/year. No other HFO external event has a CDF contribution greater than about 1.5E-7/year, which is less than the IPEEE screening criteria of 1.0E-6/year.

Based on its review of the BSEP IPEEE, the licensee concluded that the EPU has no significant effect on the plant risk profile associated with these HFO external events.

10.5.2.2.4 Staff Findings Regarding Impacts of EPU on External Events Analyses

For seismic events, the licensee previously showed in its IPEEE SMA that the BSEP plant HCLPF capacity is at least equal to the RLE value of 0.3g. Based on the facts that the EPU does not have a direct impact on the IPEEE SMA and that the licensee has resolved all the seismic outliers in a manner that satisfies the IPEEE SMA assumptions and conclusions, the NRC staff finds that the increase in risk from seismic events due to the proposed EPU is expected to be negligibly small and within the acceptance guidelines provided in RG 1.174.

For fires, the NRC staff finds that, even using the worst-case sensitivity results from the BSEP internal events PSA, the base fire CDF and the change in fire CDF due to the EPU are well within the RG 1.174 acceptance guidelines, which indicates that there is at most only a small increase in risk from fires due to the EPU.

For the HFO external events, the licensee previously showed in its IPEEE that the risk contribution from HFO external events is small, with a CDF of about 4.0E-6/year. Based on the fact that the EPU does not directly impact these HFO external events evaluations, the NRC staff finds that the increase in risk from HFO external events due to the proposed EPU is expected to be negligibly small and within the acceptance guidelines provided in RG 1.174.

The NRC staff has not identified any issues associated with the licensee's evaluation of external events that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the external events evaluation that would warrant denial of this license amendment, and the NRC staff expectation is that there will be negligible impacts from seismic events and HFO external events and at most only a small increase in the risks associated with fires as a result of the EPU.

10.5.2.3 Shutdown Risk

In the licensee's submittal and in response to an NRC staff RAI, the licensee described its shutdown risk management approach. The licensee's evaluation is presented in the following subsection, followed by the NRC staff's findings regarding the impact of EPU on shutdown risk.

10.5.2.3.1 Licensee Evaluation of Shutdown Operations

The licensee does not have a shutdown PSA model. Instead, the licensee uses a shutdown risk management program, based on the guidelines of NUMARC 91-04, "Guidelines for Industry Actions to Assess Shutdown Safety Management." The philosophy is to ensure that adequate defense-in-depth exists for those systems that mitigate postulated accidents during an unit shutdown. This philosophy and guidance for its implementation is reflected in the licensee's outage risk management procedure.

The licensee stated that the effect of the EPU on shutdown risk is similar to its effect on the at-power Level I PSA in that the shutdown risk is affected by the increase in decay heat. However, the licensee further states that the lower power operating conditions during shutdown allow for additional margin for mitigation systems and operator actions. The aspects of shutdown risk that the licensee identified as being impacted by the EPU conditions included: greater decay heat generation, longer times to shutdown, longer times before alternate decay heat removal (DHR) systems can be used, shorter times to boiling, and shorter times for operator responses. All of these aspects are basically the result of the increased decay heat generation created by the EPU.

In Enclosure 2 to the licensee’s November 30, 2001, RAI response, additional details were provided by the licensee on its evaluation of the EPU impacts on shutdown risks. The licensee identified no new initiating events or increased potential for initiating events during shutdown operations as a result of the EPU. The impact of the EPU on the success criteria during shutdown is stated as being similar to the BSEP internal events PSA. The increased power level decreases the time to boildown. However, because the reactor is already shutdown, the boildown times are relatively long compared to the at-power PSA. The boildown time is approximately 1 hour at 2 hours after shutdown (e.g., time of Hot Shutdown) and approximately 2 hours to 4 hours at 12 hours to 24 hours after shutdown (e.g., time of Cold Shutdown). The changes in the boildown time when comparing the pre-EPU case with the post-EPU case are small fractions of the total boildown time. These small changes in timing have only a negligible impact on the operator responses and associated HEPs.

The increased decay heat loads associated with the EPU do not affect the success criteria for the systems normally used to remove decay heat, but the licensee states that the EPU does impact the time when low-capacity DHR systems, such as fuel pool cooling (FPC) and RWCU, can be considered successful alternate reactor DHR systems. The EPU condition delays the time after shutdown when FPC or RWCU may be used as an alternative to SDC. However, shutdown risk is dominated during the early timeframe soon after shutdown, when the decay heat level is high and in this time frame, both the FPC and the RWCU would not be viable reactor DHR systems. Therefore, the impact of the EPU on the success criteria for the use of the FPC and RWCU as alternate reactor DHR systems is negligible.

Other success criteria are stated as being marginally impacted by the EPU. The EPU has a minor impact on shutdown RPV inventory makeup requirements because of the low makeup requirements associated with the low decay heat level. The heat load to the suppression pool is also lower than at-power because of the low decay heat level, such that the margins for the suppression pool cooling capacity are adequate for the EPU condition. The EPU impact on the success criteria for blowdown loads, RPV overpressure margin, and safety relief valve actuation is estimated by the licensee to be negligible because of the low RPV pressure and low decay heat level during shutdown.

The licensee also stated that, similar to the at-power internal events PSA, the decreased boildown time due to the EPU decreases the time available for operator actions. The risk-significant operator actions during shutdown conditions include recovering a failed DHR system or initiating alternate DHR systems. However, the longer boildown times during shutdown (i.e., hours as opposed to minutes) results in the EPU having only a minor impact on the shutdown HEPs associated with recovering or initiating DHR systems.

Based upon the above shutdown risk management evaluations, the licensee concluded that the EPU configuration will have only a negligible impact on shutdown risk.

10.5.2.3.2 Staff Findings Regarding Impacts of EPU on Shutdown Operations

The licensee identified areas associated with shutdown operations that are potentially affected by the implementation of the EPU. However, these impacts are considered minor and do not change the licensee's shutdown risk management approach.

The NRC staff has not identified any issues associated with the licensee's evaluation of shutdown risks that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the shutdown operations risk evaluation that would warrant denial of this license amendment, and the expectation is that the impact on shutdown risk due to the proposed EPU will be negligibly small, based on the licensee's current shutdown risk management process.

10.5.2.4 Quality of PSA

In the licensee's response to an NRC staff RAI, the licensee provided an overview of the quality of the BSEP internal events PSA. Further discussion of the quality of the BSEP internal events PSA is provided in Appendix C of Enclosure 2 to the November 30, 2001 RAI response. The licensee's overview is presented in the following subsection, followed by the NRC staff's findings regarding the quality of the BSEP internal events PSA for its use in this license amendment.

10.5.2.4.1 Licensee Evaluation of Quality of BSEP PSA

The licensee stated that the BSEP internal events PSA model and documentation have been maintained "living" and are routinely updated to reflect the current plant configuration following refueling outages and to reflect the accumulation of additional plant operating history and component failure data. A full upgrade of the BSEP Level I internal events PSA models began in 1998 and was completed in 2000. The BSEP Level II analysis was fully upgraded in 2001 and the Level II documentation was being finalized at the time of the licensee's November 30, 2001, RAI response.

The BSEP internal events PSA model has been subjected to an independent peer review and an industry peer review was performed during September 2001. The industry peer review addressed the eleven main technical elements and sub-elements of the BWROG peer review process and provided comments and recommendations to the licensee on specific enhancements (i.e., certification facts and observations) for the BSEP internal events PSA. The PSA peer review team's overall assessment was that the PSA could be used to support applications involving absolute risk determinations when combined with deterministic insights. This is typically referred to as an overall grade of 3 on a scale of 1 to 4, with a 1 indicating that the PSA can be used in assessing severe accident vulnerabilities and the general prioritization of issues (the lowest use) and a 4 indicating that the PSA can be used as the primary basis for decision-making (the highest use). Some issues for reassessment were also identified by the review.

The licensee evaluated the impact on the EPU evaluation from the more significant peer review results and from the current list of potential modifications and enhancements that have been identified since the latest model update. Though some of these items may result in the base CDF and LERF values increasing, the change in risk due to the EPU was judged by the licensee to remain small. This is primarily due to the fact that the identified areas for improvement in the BSEP PSA models are not in the areas impacted by the EPU.

10.5.2.4.2 Staff Findings Regarding BSEP PSA Quality

The quality of the licensee's PSA used to support a license application should be commensurate with the role that the PSA results play in the utility's and NRC staff's decision-making process and should be commensurate with the degree of rigor needed to provide a valid technical basis for the NRC staff's decision. In this case, the licensee is not requesting relaxation of any deterministic requirements for the proposed EPU and the NRC staff's approval is primarily based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights and ensuring that no new vulnerabilities are created by the EPU. The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PSA and other risk evaluations (e.g., for external events) to analyze the risks stemming from both the current, pre-EPU plant operations and the post-EPU conditions. The NRC staff's evaluation did not involve an in-depth review of the licensee's PSA. Therefore, to determine whether the PSA used in support of the license application is of sufficient quality, scope, and detail, the NRC staff evaluated the information provided by the licensee in its submittal and considered the review findings on the original BSEP IPE and IPEEE, as well as the fact that the BSEP PSA has been through an independent and industry peer review.

The NRC SER on the BSEP IPE was completed in 1995 and concluded, based on the NRC staff's "Step 1" review, that the licensee had met the intent of GL 88-20. The licensee has updated the PSA several times since the NRC staff review relative to GL 88-20 to reflect the current plant configuration and to reflect the accumulation of additional plant operating history and component failure data. Based on the independent and industry peer reviews that have been performed on the BSEP PSA and the evaluation of the impacts of the major findings of these reviews, the BSEP internal events PSA appears to be acceptable for use in this application.

The NRC SER on the BSEP IPEEE was completed in 1998 and concluded, based on the NRC staff's "Step 1" review, that the licensee's process was capable of identifying the most likely severe accidents and severe accident vulnerabilities and therefore, that the licensee had met the intent of Supplement 4 to GL 88-20. Based on the NRC staff review, as discussed in Section 10.5.2.2.4 of this SE, the IPEEE is applicable for the EPU conditions.

Therefore, the NRC staff finds that the BSEP internal events PSA is controlled and documented to ensure that it reflects the as-built, as-operated plant. The NRC staff also finds that the BSEP IPEEE is applicable to the current, pre-EPU and post-EPU conditions.

The NRC staff has not identified any issues associated with the licensee's internal events PSA and other analyses (i.e., external events analyses) that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the quality of the BSEP risk analyses and the associated EPU risk evaluation that would warrant denial of this license amendment.

10.5.3 Conclusions

The NRC staff finds that, for internal events, no new impacts are expected for initiating event frequencies, component reliability, or success criteria, but impacts are expected for selected operator actions due to the decrease in available operator response times. The NRC staff finds that the risk increases due to these impacts under the EPU conditions are within the acceptance guidelines of RG 1.174. Further, the NRC staff finds that when the licensee's proposed modification to the SLC system is implemented to support the transition to the GE14 fuel design, which is necessary to achieve the full EPU, the overall plant risk will actually be reduced.

The NRC staff finds that the licensee has a process for managing plant risk during shutdown operations and that the risk impact due to the EPU during these operations is expected to be negligibly small. The NRC staff also finds that the risk impacts from external events under EPU conditions are within the acceptance guidelines of RG 1.174.

In conclusion, during the course of its review, the NRC staff identified an issue with the manner in which the licensee calculates its change in risk values. However, the NRC staff determined that the identified issue would not significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff finds that there are no issues with the risk evaluation that would affect the licensee's ability to maintain adequate protection by meeting the deterministic requirements and regulations. This conclusion is based on the fact that the analyses are only being used to provide confirmatory insights and are not being relied upon to make NRC staff decisions.

10.6 <u>Operator Training and Human Factors</u>

10.6.1 Scope of Evaluation

This evaluation is limited to the operator performance aspects resulting from the increased allowable maximum power level. It includes required changes to operator actions, human-system interface changes, and changes to procedures and training resulting from the change in maximum power level. The evaluation is based on the licensee's response to five broad questions regarding human performance.

The NRC staff's guidance for this review includes IN 97-78, "Crediting of Operator Actions in Place of Automatic Actions and Modifications of Operator Actions, Including Response Times," and NUREG-0800, Standard Review Plan, Chapter 18 (draft), "Human Factors Engineering." In addition, ANSI/ANS 58.8, "Time Response Design Criteria for Safety Related Operator Actions," was used as an initial screening device for the significance of changes in time available for operator actions.

10.6.2 Evaluation

The NRC staff's evaluation of the licensee's responses to the five questions is provided below.

Question 1 - <u>Changes in Emergency and Abnormal Operating Procedures</u>

> Describe how the proposed power uprate will change plant emergency and abnormal procedures.

Section 11.1.2.4 of the PUSAR states operator actions in the Emergency Operating Procedures (EOPs) are not changed as a result of the EPU. However, some variable and limit curve values will change and will require modifying the EOPs to reflect these changes. CP&L, in its letter of November 7, 2001, committed to approve and implement these changes prior to raising thermal power above 2558 MWt. In a follow-up teleconference call, CP&L clarified that the same commitment included the Abnormal Operating Procedures (AOP). Since there are no changes to operator actions related to EOPs or AOPs, these commitments are satisfactory to the NRC staff.

Question 2 - Changes to Risk-Important Operator Actions Sensitive to Power Uprate

> Describe any new risk-important operator actions required as a result of the proposed power uprate. Describe changes to any current risk-important operator actions that will occur as a result of the power uprate. Explain any changes in plant risk that result from changes in risk-important operator actions.
>
> (i.e., Identify and describe operator actions that will require additional response time or will have reduced time available. Your response should address any operator workarounds that might affect these response times. Identify any operator actions that are being automated as a result of the power uprate. Provide justification for the acceptability of these changes.)

Section 10.5.3.4 of the PUSAR states that no new risk-significant operator actions resulted from the risk analysis of the EPU, nor did it identify any EPU modification that automates a risk-significant operator action. The analysis did identify four operator actions, associated with reactor pressure vessel water level control during ATWS events, in which reduced available operator response time was caused by the increase in decay heat level. In its submittal of November 7, 2001, CP&L provided detailed descriptions of these tasks along with statements of action time reductions of from 3 to 6 minutes from an original 30-minute allowable time. Based on examination of the ATWS EOP indications and action directions, required control board manipulations, and feedback indications that the actions were successful, the NRC staff is satisfied that the reduced time available is still sufficient to successfully perform the tasks. (See Section 10.5.2.1.4 for the effect these time reductions may have on plant risk.)

Question 3 - Changes to Control Room Controls, Displays and Alarms

> Describe any changes the proposed power uprate will have on the operator interfaces for the control room controls, displays and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What set points will change? How will the operators know of the change? Describe any controls, displays and alarms that will be upgraded from analog to digital instruments as a result of the proposed power uprate and how operators were tested to determine they could use the instruments reliably.

In its submittal of November 7, 2001, CP&L provided a comprehensive list of controls, displays, alarms, instructional aids and systems to be added, replaced with upgraded equipment, rescaled and rezoned as a result of the EPU. It provided a list setpoints and other changes to be made prior to the first phase 6% power increase and a separate list of anticipated changes to be accomplished prior to the second phase 9% increase. Further evaluations are to be made which may result in changes to these lists, thus the lists are not yet CP&L commitments. See the response to Question 5 as to how the operators will know of the changes to the control room.

The purpose of this question is to ensure the NRC staff that the licensee has adequately considered the equipment changes resulting from the EPU that affect the operators' ability to perform their required functions. Based on the CP&L response, the NRC staff is satisfied it has done so.

Question 4 - Changes on the Safety Parameter Display System

> Describe any changes the proposed power uprate will have on the Safety Parameter Display System. How will the operators know of the changes?

Section 11.1.2.4 of the PUSAR states that the Safety Parameter Display System (SPDS) may contain curves and limits, which may be updated, if necessary. The response to the NRC staff's RAI dated November 7, 2001, contains a commitment that any changes in the SPDS relating to the EOPs and resulting from the EPU project will be approved and implemented prior to raising power above 2558 MWt on the affected unit. See the response to Question 5 as to how the operators will know of the SPDS changes. This commitment is satisfactory to the NRC staff.

Question 5 - Changes to the Operator Training Program and the Control Room Simulator

> Describe any changes the proposed power uprate will have on the operator training program and the plant reference control room simulator, and provide the implementation schedule for making the changes.

The CP&L letter dated November 7, 2001, stated that Brunswick Training Section (BTS) representatives are active in the EPU modification process, including Engineering Service Request reviews, feedback and approval. Designated training personnel in Operations are responsible for implementing EPU training in accordance with the approved Systematic Approach to Training process as outlined in BTS procedures. This process includes needs, job and task analyses for each EPU modification and appropriate training materials are being generated and/or updated. Training was begun in mid-2001 and has been scheduled through May 2002. It includes training on the new Power Range Neutron Monitoring (PRNM) system and systems and procedures modifications resulting from the EPU.

The Brunswick Control Room Simulator is undergoing a planned two-phase process to install EPU modifications in order to support the above training. The first phase will include installation of the PRNM and several other EPU and non-EPU system modifications. In conjunction with the Unit 1 plant outage the second phase simulator modification will include installation of core model changes to support plant operation at the first phase of the EPU. CP&L commits to complete the appropriate training and simulator upgrades necessary to support the first phase of the EPU prior to increasing power above 2558 MWt on each unit. CP&L further commits to complete any additional training and simulator upgrades necessary to support the second phase of the EPU prior to increasing power above the first phase level on each unit. CP&L further states that the simulator changes and fidelity revalidation will be performed in accordance with ANSI/ANS 3.5-1998.

The NRC staff is satisfied that, based on the above commitments, following the approved Systematic Approach to Training process for training and using the NRC endorsed ANSI/ANS 3.5-1998, CP&L will develop and implement a satisfactory simulator EPU training program for Brunswick Units 1 and 2.

10.6.3 Conclusion

The NRC staff concludes that the review topics associated with the operator's integration into the proposed extended power uprated system have been satisfactorily addressed by the licensee. The NRC staff further concludes that the proposed extended power uprate should not adversely affect operator performance based on the reduced time available on several risk-important operator actions.

10.7 Plant Life

The licensee evaluated the longevity of plant equipment affected by the power uprate and concluded that most equipment is not affected by the EPU. The licensee also acknowledged that the reactor internals see significant additional fluence because of EPU. However, the licensee is committed to follow the inspection strategy recommended by the BWR Vessel Internals Project (BWRVIP). The NRC staff has approved the inspection strategy developed by BWRVIP and, therefore, compliance with the inspection recommendations will ensure that degradation of reactor internals will be promptly identified and corrected.

11.0 LICENSE AND TS CHANGES

11.1 License Conditions

The following license conditions were submitted by the licensee in letters to the NRC dated March 25, 2002, and April 29, 2002. The NRC staff has reviewed these and finds them acceptable.

Amendment Number	Additional Conditions	Implementation Date
Amendment No.	The licensee shall submit a license amendment request, revising Technical Specification Section 3.1.7, "Standby Liquid Control (SLC) System," to ensure the SLC system: (1) remains capable of bringing the reactor to a subcritical condition with the reactor in the most reactive, xenon free state without taking credit for control rod movement, and(2) continues to meet the requirements of 10 CFR 50.62.	The Unit 1 license amendment request shall be submitted to the NRC by August 29, 2003.
Amendment No.	The licensee shall modify the Standby Liquid Control (SLC) system by increasing neutron absorber concentration.	Prior to startup following the Unit 1 Cycle 15 Refueling Outage

Amendment No.	The licensee shall submit a license amendment request, revising Technical Specification Section 3.1.7, "Standby Liquid Control (SLC) System," to ensure the SLC system: (1) remains capable of bringing the reactor to a subcritical condition with the reactor in the most reactive, xenon free state without taking credit for control rod movement, and(2) continues to meet the requirements of 10 CFR 50.62.	The Unit 2 license amendment request shall be submitted to the NRC by August 30, 2002.
Amendment No.	The licensee shall modify the Standby Liquid Control (SLC) system by increasing neutron absorber concentration.	Prior to startup following the Unit 2 Cycle 16 Refueling Outage

11.2 Technical Specifications

The NRC staff reviewed the following proposed TS changes submitted by the licensee in Table 11-1 of GE NEDC-33039P.

TS Item	Description of change
Section 1.1, Definitions	Revised the definition of RATED THERMAL POWER to be the EPU maximum licensed power level of 2923 MWt. (Reference PUSAR Section 1.2.1)
Safety Limit (SL) 2.1.1.1	Revised the SL for fuel cladding integrity at low core flow and reactor pressure from 25% RTP to 23% RTP. (Reference PUSAR Section 9.1)
Limiting Condition for Operation (LCO) 3.1.3: - Condition D; LCO 3.1.6: - Applicability; LCO 3.3.2.1: - Surveillance Requirement (SR) 3.3.2.1.2 - SR 3.3.2.1.3 - SR 3.3.2.1.5 - Table 3.3.2.1 -1, Note (f)	Revised the applicable THERMAL POWER from 10% RTP to 8.75% RTP. (Reference PUSAR Section 5.3.12)

LCO 3.2.1: - Applicability - Required Action B. I - SR 3.2.1.1 LCO 3.2.2: - Applicability - Required Action B.I - SR 3.2.2.1	Revised the percentage of RTP value contained in the SR and the associated NOTE from 25% RTP to 23% RTP. (Reference PUSAR Section 9.1)
LCO 3.3.1.1: - SR 3.3.1.1.3	Revised the percentage of RTP value contained in the SR and the associated NOTE from 25% RTP to 23% RTP. This value establishes the minimum power level at which the average power range monitors (APRM) are adjusted to conform to the calculated power. (Reference PUSAR Section 9.1)
LCO 3.3.1.1: Required Action E.1 SR 3.3.1.1.16 Table 3.3.1.1-1, Functions 8 and 9	Revised the percentage of RTP value from 30% RTP to 26% RTP. This value corresponds to the power level at which the Turbine Stop Valve closure and Turbine Control Valve fast closure trips the Reactor Protection System are bypassed. (Reference PUSAR Section 5.3.11 and Table 5-1)
LCO 3.3.1.1 Table 3.3.1.1-1, Function 2b Footnote (b)	Revised the allowable value for the APRM Simulated Thermal Power - High from 0.66W + 62.0 %RTP to 0.55W + 62.6 %RTP For single loop operation, revised the allowable value for the APRM Simulated Thermal Power - High from 0.66(W - AW) + 62.0 %RTP to 0.55(W - AW) + 62.6 %RTP (Reference PUSAR Section 5.3.5 and Table 5-1)
LCO 3.3.2.2 - Applicability - Required Action C.1	Revised the percentage of RTP value at which the Feedwater and Main Turbine High Water Level Trip Instrumentation is required OPERABLE from 25% RTP to 23% RTP. (Reference PUSAR Section 9.1)
LCO 3.7.6: - Applicability - Required Action B.I	Revised the percentage of RTP value at which the Main Turbine Bypass Valve system is required OPERABLE from 25% RTP to 23% RTP. (Reference PUSAR Section 9.1)

11.2.1 NRC Staff's Evaluation of Proposed TS Changes

TS Section 1.1, Definitions

The definition of RTP would be revised to be the proposed EPU maximum licensed power level of 2923 MWt.

This is the new maximum licensed power level, based on the licensee's safety analysis Safety Analysis Report and BOP evaluations. The NRC staff has reviewed this and determined that this is an editorial change required to be consistent with the approved EPU.

Safety Limit 2.1.1.1

The safety limit would be revised for fuel cladding integrity at low core flow and reactor pressure from the current 25% RTP to 23% RTP . The 23% value was selected by the licensee on the basis of the average fuel bundle power in the BSEP units, the number of fuel bundles in the reactor, and the EPU power level, which accounts for the difference between the generic BWR/6 design used for the original setpoint AL and the BWR/4 design of the BSEP units. Additionally, at low power levels the margin to the MCPR and the average planar linear heat generation rate (APLHGR) is sufficiently large to allow the relatively marginal difference in lower limits. Therefore, the NRC staff finds the proposed change in the thermal power limit from >25% RTP to >23% EPU RTP to be acceptable.

LCO 3.2.1: Applicability, Required Action B.1, and SR 3.2.1.1

LCO 3.2.2: Applicability, Required Action B.1, and SR 3.2.2.1

LCO 3.7.6: Applicability, Required Action B.1

The above changes to the TS LCO 3.2.1, 3.2.2, 3.7.6, and associated Required Actions and SR would be made to be consistent with the change proposed for Safety Limit 2.1.1.1. The NRC staff has reviewed the technical basis for these changes in this SE and finds these changes consistent with guidance previously approved by the NRC, and they are therefore acceptable.

LCO 3.3.1.1: Required Action E.1, SR 3.3.1.1.16, and Table 3.3.1.1-1, Functions 8 and 9,

The existing Required Action E.1 requires the licensee to reduce thermal power to <30% RTP. The proposed amendment requires the licensee to reduce thermal power to <26% (EPU) RTP. The equivalent absolute thermal powers are 767.4 MWt and 760.0 MWt, respectively. The reduction in power is more conservative after the EPU in terms of absolute power. Therefore, the NRC staff finds the proposed reduction of thermal power to <26% EPU RTP acceptable.

The existing SR 3.3.1.1.16 requires the licensee to verify Turbine Stop Valve-Closure, Turbine Control Valve Fast Closure, and Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥30% RTP. The proposed amendment requires the verification to be performed when (EPU) THERMAL POWER is ≥26% RTP. As discussed above, 26% EPU RTP is more conservative than the existing 30% RTP in terms of absolute power. Therefore, the NRC staff finds this TS amendment to be acceptable.

The existing applicable conditions for Functions 8 and 9 in Table 3.3.1.1-1 are RTP ≥30% RTP. The proposed amendment requires the EPU RTP to be ≥26% RTP. As discussed above, the 26% EPU RTP is more conservative than the existing 30% RTP in terms of absolute power. Therefore, the NRC staff finds this amendment to be acceptable.

<u>LCO 3.3.1.1: SR 3.3.1.1.3</u>

The Note for the existing SR 3.3.1.1.3 states, "Not required to be performed until 12 hours after THERMAL POWER ≥25% RTP." The proposed amendment revises the Note to state, "Not required to be performed until 12 hours after THERMAL POWER ≥23% RTP." The reduction of the thermal power limit from 25% RTP (639.5 MWt) to 23% EPU RTP (672.3 MWt) results in an apparent nonconservative limit. The 23% value was selected by the licensee on the basis of the average fuel bundle power in the BSEP units, the number of fuel bundles in the reactor, and the EPU power level, which accounts for the difference between the generic BWR/6 design used for the original setpoint AL and the BWR/4 design of the BSEP units. Additionally, at low power levels the margin to the MCPR and the APLHGR are sufficiently large to allow the relatively marginal difference in lower limits. Therefore, the NRC staff finds the proposed change in the thermal power limit from >25% RTP to >23% EPU RTP to be acceptable.

The existing SR 3.3.1.1.3 requires the licensee to adjust the APRM channels to conform to the calculated power while operating at ≥25% RTP. The proposed SR 3.3.1.1.3 revises the lower power limit to ≥23% (EPU) RTP. As described above, increasing the absolute power lower limit from 25% RTP (639.5 MWt) to 23% EPU RTP (672.3 MWt) was justified by the licensee on the basis of the average fuel bundle power in the BSEP units, the number of fuel bundles in the reactor, and the EPU power level, which accounts for the difference between the generic BWR/6 design used for the original setpoint AL and the BWR/4 design of the BSEP units. Additionally, at low power levels the margin to the MCPR and the APLHGR is sufficiently large to allow the relatively marginal difference in lower limits. Therefore, the NRC staff finds the proposed change in the thermal power limit to be acceptable.

<u>LCO 3.3.1.1: Table 3.3.1.1-1, Function 2b and Footnote (b)</u>

The existing Table 3.3.1.1-1 Function 2b (APRM Simulated Thermal Power-High) AV is represented by the relationship, *Function 2b* $\leq 0.66W + 62.0\%$ *RTP*. The licensee proposed an equivalent relationship that incorporated an increase in the Power/Flow map operating region due to the power uprate. The proposed relationship for the EPU Function 2b is: *Function 2b* $\leq 0.55W + 62.6\%$ *RTP*. The proposed EPU Function 2b AV is marginally less than the existing Function 2b AV and is, therefore, more conservative with respect to the margin to scram from the MELLLA. Therefore, the NRC staff finds this proposed change acceptable.

The licensee proposed changing the existing footnote for Table 3.3.1.1-1 Function 2b to correspond to the proposed AV discussed above. The existing single loop operation AV relationship is: *Function 2b* $\leq [0.66(W - \Delta W) + 62.0\%$ *RTP*$]$. The proposed single loop operation AV relationship is: *Function 2b* $\leq [0.55(W - \Delta W) + 62.6\%$ *RTP*$]$. The proposed change incorporates the AV function change proposed by the licensee and, therefore, is acceptable.

<u>LCO 3.3.2.1: SR 3.3.2.1.2, SR 3.3.2.1.3, SR 3.3.2.1.5, Table 3.3.2. 1 - 1, Note (f)</u>

The existing TS 3.3.2.1, Control Rod Block Instrumentation, SR 3.3.2.1.2 and SR 3.3.2.1.3 Notes state, "Not required to be performed until 1 hour after any control rod is withdrawn at ≤10% RTP in MODE 2." The proposed Note states, "Not required to be performed until 1 hour after any control rod is withdrawn at ≤8.75% RTP in MODE 2.” The LPSP is based on total steam flow as a measure of reactor power, and will remain constant in terms of absolute thermal power and steam flow. The proposed 8.75% (EPU) RTP is equivalent to the existing minimum RTP value for performing SR 3.3.2.1.2 and SR 3.3.2.1.3 and, therefore, these proposed changes to the Notes are acceptable.

The existing SR 3.3.2.1.5 for TS 3.3.2.1 states, “Verify the RWM is not bypassed when THERMAL POWER is ≤10% RTP” The proposed Note states, “Verify the RWM is not bypassed when THERMAL POWER is ≤8.75%.” As stated in Section 3.1.3 above, the function of the RWM is to support the operator by enforcing rod patterns until reactor power increases to the LPSP. Above the LPSP, sufficient negative reactivity feedback mechanisms exist to limit the severity of a worst-case CRDA. The RWM LPSP is based on total steam flow as a measure of reactor power, and will remain constant in terms of absolute thermal power and steam flow. The proposed 8.75% (EPU) RTP is equivalent to the existing minimum RTP value for performing SR

<u>LCO 3.1.3: Condition D;</u>

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a control rod drop accident. The banked position withdrawal sequence (BPWS) is enforced by the Rod Worth Minimizer (RWM). Condition D (i.e., the percent RTP at which inoperable control rods, not in compliance with BPWS, need to be restored) is revised, consistent with the operability requirements of the RWM, discussed in LCO 3.3.2.1, above. The revised percent of RTP remains constant with the existing percent RTP in terms of absolute thermal power and steam flow. Therefore, the NRC staff finds the proposed change in operability requirements to be acceptable.

<u>LCO 3.1.6: Applicability</u>

Control rod patterns during startup conditions are controlled by the operator and the RWM which enforces the BPWS. Therefore, the applicability of TS 3.1.6 is revised, consistent with the operability requirements of the RWM, discussed in LCO 3.3.2.1, above. The revised percent of RTP remains constant with the existing percent RTP in terms of absolute thermal power and steam flow. Therefore, the NRC staff finds the proposed change in operability requirements to be acceptable.

<u>LCO 3.3.2.2: Applicability, Required Action C.1</u>

The existing TS 3.3.2.2, Feedwater and Main Turbine High Water Level Trip Instrumentation, Applicability and Required Action C.1 set the threshold thermal power at 25% RTP. The proposed change reduces the thermal power limit to 23% (EPU) RTP. As described above in the discussion regarding the proposed change to TS 3.3.1.1 SR 3.3.1.1.3, increasing the absolute power lower limit from 25% RTP (639.5 MWt) to 23% EPU RTP (672.3 MWt) was justified by the licensee on the basis of the average fuel bundle power in the BSEP units, the number of fuel bundles in the reactor, and the EPU power level, which accounts for the difference between the generic BWR/6 design used for the original setpoint AL and the BWR/4 design of the BSEP units. Additionally, at low power levels the margin to the MCPR and the APLHGR is sufficiently large to allow the relatively marginal difference in lower limits. Therefore, the NRC staff finds the proposed change in the thermal power limit to be acceptable.

The NRC staff reviewed the proposed TS Bases related to the above TS changes and finds the proposed changes to be acceptable.

12.0 ONSITE AUDIT

The PUSAR provided the results and conclusions of the safety analyses and system performance evaluations supporting operation of BSEP Units 1 and 2 at the EPU power level. In addition, the BSEP Units 1 and 2 EPU SAR deviated from the ELTR1 guidelines in the thermal assessment, LOCA, transients and stability setpoints analysis. Therefore, five NRC staff members visited the GENE facility in San Jose, California on December 3 to 6, 2001, to perform a detailed onsite review to determine if the deviations in the ECCS-LOCA analyses, the transient analysis and the stability setpoint calculations could adequately support approving the BSEP Units 1 and 2 EPU operation. Specifically, the objectives of the audit were,

- to evaluate the limited ECCS-LOCA analysis approach to determine whether the analysis performed, the corresponding justification, and the adequacy of the ECCS-LOCA approach support the BSEP Units 1 and 2 during EPU operation,

- to confirm that the available Unit 1 Cycle 14 EPU transient analysis,

- to review the EPU core design changes using the available BSEP Unit 1, Cycle 14 EPU core design,

- to review the thermal limits evaluation and related fuel design issues,

- to review selected system capability and performance evaluations to determine how the licensee concluded that systems would be able to perform their intended function at the EPU operating conditions,

- to review the long-term Option III stability solution that the licensee plans to implement, and

- to review the key input parameters used in the ATWS analysis. The NRC staff reviewed the capability of the SLC system to inject borated solution at the flow rate equivalent to 86 gpm without lifting of the SLC system's bypass relief valves for all of the analyzed ATWS events.

The NRC staff conducted an audit of GE's design record files as well as the Project TASK reports GE provides to the licensee. These reports contain the key input parameters and assumptions used in the analysis, the results of the analysis and the basis for the conclusions provided in the PUSAR. The NRC staff also consulted both the GE and the licensee staff members responsible for the specific analysis. At the conclusion of the audit, the NRC staff generated an RAI to document the information needed to make the NRC staff's findings. The areas audited and the corresponding RAI responses are discussed in the respective sections of the SE. The following audit sections outline the areas audited and summarize the NRC staff's conclusion.

12.1 Fuel Design Limits and EPU Core Design

12.1.1 Unit 1 Cycle 14, EPU Core design

During the on-site audit, the NRC staff reviewed the BSEP Unit 1 Cycle 14 EPU core design relative to the Cycle 13 core design and confirmed that the core radial power distribution would be flatter, with high powered bundles near the periphery of the core. The enrichment and burnable poisons varied for the GE14 fuel and the batch fraction would increased to achieve the EPU energy requirements. For Unit 1, Cycle 14, the licensee loaded the first batch of GE14 fuel, and to achieve the EPU power level, the licensee would have to load second batch of GE14. Although the licensee loaded a large batch size and increased the enrichment of the fuel bundles, the licensed enrichment limit was not exceeded. Four different types of GE14 fuel with varying poison and enrichment were loaded into the core, but the thermal-mechanical design of the GE14 fuel did not change. The high powered bundles were also placed in the periphery of the core, therefore, the three areas of loading (center, average and periphery) used in the initial core designs are no longer applicable.

12.1.2 LHGR and MAPLHGR

During the audit, the NRC staff reviewed how the MAPLHGR curve is derived and asked GE to explain how the MAPLHGR and maximum LHGR will be maintained for mixed core of GE13 and GE14 fuels for the EPU operation. If there are differences between the MAPLHGR or LHGR curves for the EPU operation, the NRC staff asked GE to provide the curves for EPU and pre-EPU conditions.

For each fuel design, GE established a peak LHGR curve and a MAPLHGR curve that is derived from the LHGR. These two curves form the basis for analyzing the thermal-mechanical and the LOCA affects. During the Brunswick audit, the NRC staff discovered that the GE13 and the GE14 fuel design LHGR limits used in the BSEP Unit 1 core design were different from the original GE14 and GE13 design curves. In a response to the NRC staff’s RAI, the licensee presented the LHGR curves for the Brunswick GE13 and GE14 fuel design, which showed slight variation from the original design curves for these fuel bundles. For the GE13 and GE14 fuel designs, the LHGR and MAPLHGR limits are specified in NEDE-32198P, “GE13 compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II),” and NEDC-32868P, Revision 1, “GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II),” respectively. Since the BSEP LHGR versus exposure curves for the GE14 and GE13 curves remain bounded by the reference fuel design curves and the fuel design is based on NRC-approved process, the NRC staff concluded that the LHGR and MAPLHGR limits are acceptable for the Brunswick EPU operation.

12.1.3 SLMCPR

The NRC staff audited the Unit 1, Cycle 14 core design and the reload safety analysis used to establish the SLMCPR and the operating limit MCPR change for Unit 1, Cycle 14. The key parameters used by GE to quantify the bundle-to-bundle power distribution and the pin-to-pin power distribution indicate that both the radial (bundle to bundle) power distribution and the pin-to-pin power distribution would be flatter. The flatness of the pin-to-pin and bundle-to-bundle power distribution for the Cycle 14 core design were compared against to the Cycle 13 core design. The power distribution is one of the parameters that affect the SLMCPR. Therefore, the EPU SLMCPR increased by 0.02. This value is within the range predicted by GE as the potential EPU affect on the SLMCPR.

12.1.4 Oxidation and Crud Buildup

Recently, oxidation and crud have emerged as a potential concern for fuel design performance due to cladding degradation and increased flow resistance. During the EPU operation, the fuel rods in a bundle can experience higher temperatures that may result in more oxidation and crud buildup. The NRC staff's audit considered the predicted highest corrosion level accumulated for operation at the EPU power level and whether the amount of crud and corrosion in spent fuel pool would increase. The NRC staff also looked at how the corrosion deposits on fuel rods account for the activated corrosion products. In a follow-up RAI, the licensee explained that corrosion or crud would be expected to increase slightly due to the increased feedwater flow. However, the licensee confirmed that the small increase of corrosion or crud will not cause any adverse effect on the fuel performance during operation at the higher power. In addition, the licensee indicated that the spent fuel pool cooling and cleanup system will have sufficient capability to remove the excessive crud layers. The potential increase in crud may result in slightly more frequent backwash of the filter-demineralizer or replacement of the resins. Based on the review of the audit material, subsequent discussion, and the RAI response, the NRC staff agreed with the licensee assessment that the small increase of corrosion or crud will not present a problem for the Brunswick EPU operation.

12.2 Implementation of the Option III Long-Term Stability Solution

The purpose of the audit of the stability detect and suppress methods was to ensure that: (1) the generic position developed by the BWR Owners' Group is still valid for the plant-specific application of the options (i.e. BWROG Long-Term Stability Solutions Licensing Methodology including Enhanced Option I-A, Option I-D, Option II, and Option III); (2) the plant-specific application for the selected Option was analyzed according to the NRC staff's approved methodology; (3) the operators have been trained according to the operating training, emergency procedures, and approved TS; and (4) the maintenance rule is applied to this Option in a timely fashion.

The NRC staff had performed several audits of the stability solutions for other EPU applications, including Duane Arnold (Option I-D), Dresden and Quad City (Option III), Clinton (Option III), and Brunswick (Option III). The NRC staff also audited the Perry (Option III) implementation prior to auditing the implementations of the stability solutions of the EPU plants.

In the previous audits, the NRC staff had reviewed the applicability of the BWROG approved generic DIVOM (Delta Critical Power Ratio (CPR) Over Initial MCPR Versus Oscillation Magnitude) curve specified in NEDO-32465-A to each plant's long-term stability Option for the EPU operation. During the Duane Arnold audit, the NRC staff identified a 10CFR Part 21 issue related to a non-conservative generic regional mode DIVOM curve application for the other Options.

For the Brunswick Units 1 and 2 EPU audit, the NRC staff reviewed Project Task Report GENE-C51-00251-00-01 for the Brunswick Reactor Long-Term Stability, Option III Licensing Basis Hot Bundle Oscillation Magnitude. The NRC staff evaluated how the long-term stability detect and suppress solution methods would deal with the mixed core reload involving fuel from two different fuel vendors. For Brunswick, the NRC staff concluded that CP&L's plan to address the 10 CFR Part 21 DIVOM curve issue is acceptable. The licensee will operate Brunswick Unit 1 with the OPRM trip function operable if the existing generic regional DIVOM curve is applicable, or will enable the OPRM but declared it inoperable if the generic curve is not bounding for Brunswick operation. In the latter case, the licensee will avoid instability using the NRC staff-approved ICAs until the DIVOM curve issue is resolved.

12.3 Confirmation of the Unit 1 Cycle 14 EPU Transient Analysis

At the time of the NRC staff's audit, the Unit 1, Cycle 14 reload analysis was completed. Although the EPU core design was based on a single reload batch of GE14, and the licensee was uprating in stages, the licensee performed all the limiting transient analysis at the EPU power level. Therefore, the Unit 1, Cycle 14 reload analysis provided sufficient basis to demonstrate the unit's response to an AOO at the EPU power level. The NRC staff compared the results of the plant's transient response at the CRTP and at the EPU condition. The NRC staff found that the delta critical power ratio (CPR) was, in some cases, higher for the CRTP than the EPU condition, but the effect of the higher power on the transient response was within the range predicted by the GE. In an RAI response, GE explained that [

] For the EPU condition, similar to all rated condition in comparison to the offrated, the increase in the feedwater flow to maximum demand is less, resulting in lower change in the delta CPR. The NRC staff found this explanation acceptable for the observed lower delta CPR for the EPU operation.

ELTR1 guidelines recommended that a set of transient analyses be performed to support the EPU operation and that these transient analyses be based on a representative equilibrium core. [ ] The NRC staff confirmed that the limiting transient analyses deferred to the reload analysis were performed. Table 1.0 in Section 9.1, "Reactor Transients," of this SE lists the transient analyses deferred to the reload and discusses the NRC staff's confirmation. The NRC staff found that the licensee did perform the transient analysis and the plant's response demonstrates the feasibility of operation at the EPU conditions while ensuring the fuel design limits would be met.

12.4 The Limited ECCS-LOCA Performance Analysis

In the audit of this section, the NRC staff focused on determining what the ECCS-LOCA deviation entailed. The NRC staff (1) identified the number of small and large breaks that were analyzed, (2) determined at what power level was all the resident fuel analyzed, (3) evaluated how the limiting fuel was selected, (4) determined for the limiting fuel what PCTs are actually calculated, and (5) evaluated if the method used to determine the licensing basis and upper bound PCTs were consistent with the SAFER/GESTR-LOCA methodology. The NRC staff asked the licensee to justify the basis for the limited ECCS-LOCA approach and the justifications are documented in the RAIs generated during the audit. After review of the ECCS-LOCA results at the uprated conditions and the technical justifications provided by GE, the NRC staff has concluded that the net effect on the PCT due solely to increased thermal power is not significant. The NRC staff believes that for the EPU core design, the number of bundles experiencing the peak PCT might be higher, but since the calculated values are well below 2200°F, this effect does not change the acceptability of the ECCS-LOCA performance at the EPU conditions.

The NRC staff also reviewed some aspects of the ECCS-LOCA design record files to evaluate the key input parameters used in the analysis and compliance with the NRC-approved method. For example, the NRC staff confirmed that the peak LHGR used for the Appendix K calculations included the 2 percent uncertainty. For the GE14 fuel, the Appendix K calculations for the hot bundle use a peak LHGR of 13.4 KW/ft x 1.02. In addition, since the ECCS-LOCA analysis assumed an OLMCPR value, the NRC staff asked GE how the assumed OLMCPR for the ECCS-LOCA OLMCPR is tracked in subsequent cycles. GE confirmed that the OLMCPR value used in the ECCS-LOCA analysis is currently reported in the supplemental reload licensing report (SRLR) and the ECCS-LOCA OLMCPR limits the plants operation below that value. The NRC staff reviewed the key parameters used in the ECCS-LOCA and did not find any inconsistencies in the analysis method.

The NRC staff also noted that the limited ECCS-LOCA performance evaluation was based on Unit 2, which was considered more limiting because of the more restrictive orifices in Unit 2. The NRC staff reviewed the ECCS-LOCA results for Brunswick Unit 2 and the NRC staff's evaluation and conclusions are discussed in Section 4.3 of this document.

12.5 Reactor System Performance

The NRC staff reviewed GE's system capability and performance evaluations for (1) the recirculation system, (2) the RCIC, (3) SLC, (4) the shutdown cooling system, (5) the CRD system, and (6) low-pressure ECCS systems. The NRC staff reviewed the system task reports to determine the adequacy of the system performance evaluations. The NRC staff considered the key input parameters and assumptions used in the evaluations, the characterization of the impact of the EPU operation on the system and the basis for the conclusion that the system can perform its function. Key results were reviewed to verify that the results comply with the acceptance criteria. Supporting evaluations such as pump performance, pump NPSH requirements, system reliability, relief valves, valves capability, setpoints, electrical power requirements, testing were reviewed. The following packages were reviewed:

(a) GE-NE-A22-00113-15-01, Rev.0 BSNP Task T0309, RCIC, May 2001

(b) GE-NE-A22-00113-37-01, Rev.0 BSNP Task 0609, SLCS, May 2001

(c) GE-NE-A-22-00113-25-01 Rev. 0 BSNP Task 0405, CS system, May 2001

(d) GE-NE-A-22-00113-24-01 Rev. 0 BSNP Task 0405, HPCI, April 2001

(e) GE-NE-A-22-00113-13-01 Rev. 0 BSNP Task 0307, Reactor Recirc: System ,May 2001

(f) GE-NE-A-22-00113-05-01 Rev.0 BSNP Task 0203, CRD System, May 2001

(g) GE-NE-A-22-00113-16-01 Rev.0 BSNP Task 0310, RHR System

Most of the NRC staff's questions, comments and clarifications on the above task reports were satisfactorily addressed by GE and the licensee. Areas that the NRC staff found required further documentation or resolution were included in the audit RAIs. The NRC staff further reviewed the following system issues.

12.5.1 The SLC System

The NRC staff found that the SLC system relief margin evaluation was not discussed in the PUSAR. During the audit, the SLC bypass relief valve margin seemed inadequate and the NRC staff issued a series of RAIs on this issue. Section 6.5 of this document covers the resolution of the SLC relief valve margin.

12.5.2 Power/Flow Map and the Recirculation System

GE's evaluation of the recirculation system covered the system's capability to meet the pump drive flow requirements, suction and discharge valve pressure and temperature, jet pump hydraulic performance and instrumentation, net positive suction head requirements for the RR and jet pumps, and applicability of the power/flow map cavitation protection.

The NRC staff found that the Unit 2 recirculation system did not have sufficient capability to provide necessary drive flow for Unit 2 to achieve the maximum core flow operation at the EPU conditions. The recirculation system cannot provide sufficient drive flow at the EPU conditions to overcome the large hydraulic losses associated with the Unit 2 restrictive orifice sizes, combined with the higher flow resistance. In general, the recirculation system performance evaluation is also based on the as-designed condition and does not take into account any degraded conditions, which may limit further the capability of the system. The NRC staff found that the Unit 2 jet pump may experience additional flow losses due to crud built-up. In Section 2.3.1, "Power/Flow Operating Map," and Section 3.4, "Recirculation System," the NRC staff evaluated the potential safety impact of the limitations of the recirculation system at the increased flow region.

The higher loads required to meet the increased drive flow will require the pump motors to exceed their horsepower and electric current rating. The NRC staff discussed this with the GE staff to determine if this would lead to higher incidents of recirculation pump trips at the increased core flow range. Based on the design of the recirculation system motor generator set, the NRC staff was assured that operation above the nameplate rating would not increase the incidence of RPT. The NRC staff found that GE evaluated the RR system capability and identified potential limitations and the NRC staff found the conclusions of the RR performance evaluations acceptable.

12.5.3 RCIC

The RCIC task report states that "rod drop accident (RDA) analysis is bounded by the loss of feedwater analysis (LOFW)." The NRC staff requested a clarification of this statement since these two events are different: RDA is an accident and LOFW is a transient. The acceptance criteria are different for an accident and a transient. In an RAI response, the licensee clarified that the system response for the LOFW analysis bounds the system response for the RDA. The licensee confirmed that the most applicable site-specific accident evaluation for bounding the RDA is the main steamline break outside containment evaluation. This is acceptable.

The RCIC performance evaluation determined that the system had the capability to maintain water level above the TAF for the design-basis LOFW. The evaluation determined that the BSEP units would not be able to avoid isolation during an LOFW event, due to the higher decay heat. The licensee, therefore, performed an LOFW transient analysis with isolation. However, the NRC staff found that the RCIC injection capability and pump turbine overspeed evaluation did not include a discussion of the system's capability to inject the rated flow without turbine overspeed for an LOFW event with isolation. The NRC staff issued an RAI on this issue and the RCIC performance at the EPU condition is discussed in Section 3.8 of this document.

12.5.4 Shutdown Cooling

The calculated time for cooling the reactor to 125°F for EPU operation was not specified. In its March 12, 2002, response to an NRC RAI, the licensee confirmed that the reactor can be cooled to 212°F in approximately 10 hours using only one RR shutdown cooling loop. This is acceptable.

12. 6 Anticipated Transient Without Scram (ATWS) Instability

12.6.1 Background

Unstable power oscillations can occur during plant maneuvers or under transient conditions and long-term stability solutions have been developed to detect and suppress these power oscillations. To address concerns that arose regarding unstable power oscillations during an ATWS, the BWROG submitted two topical reports to the NRC staff: NEDO-32047-A, "ATWS Rule Issues Relative to BWR Core Thermal-Hydraulic Stability," and NEDO-32164, "Mitigation of BWR Core Thermal-Hydraulic instabilities in ATWS." On the basis of these evaluations, the BWROG and GE concluded that the mitigation strategies effectively prevent fuel failures and boron injection terminates the instability. In an SE dated February 5, 1994, the NRC staff reviewed and accepted the two topical reports. With its acceptance of these two reports, the NRC staff concluded that the recommended operator actions (e.g., lowering water level below the feedwater nozzles and initiating the SLC system early in the event) are appropriate to mitigate an ATWS event with oscillations. The NRC staff further reviewed the ATWS mitigation strategies in Revision 4 of the BWR EPGs and in a June 6, 1996, safety evaluation, "Acceptance of Proposed Modifications to the BWR EPG," the NRC staff recommended the optimal water level control strategy for ATWS.

In an RAI response, the licensee stated that the BSEP emergency operating procedures (EOPs) have been developed consistent with the BWROG Emergency Procedure Guidelines (EPG) in NEDO-31331. The BSEP Units 1 and 2 EOPs ATWS control strategies include the following operator actions: (1) terminate feedwater flow, (2) initiate the SLC system, (3) start RHR in the pool cooling mode, and (4) maintain RPV water level above the minimum steam cooling water level (MSCWL) and 2 feet below the feedwater spargers. For the water level control, the licensee stated that BSEP Units 1 and 2 ATWS mitigation strategy incorporated the modifications proposed in the NRC staff's June 6, 1996, SE, which recommended maintaining the water level between the MSCWL and 2 feet below the feedwater spargers. Since the licensee's ATWS control strategies follow the NRC staff's recommendations and the NRC-approved ATWS mitigation strategies in Revision 4 of the EPGs, the NRC staff concludes that ATWS mitigation strategies in the BSEP Units 1 and 2 EOPs, as documented in the RAI response, are acceptable.

12.6.2 BSEP Units 1 and 2 ATWS/Instability Response Evaluation

The NRC staff evaluated the applicability of the generic ATWS instability analyses described in the two topical reports to the BSEP Units 1 and 2 EPU operation. A plant's instability response is influenced by its physical design, core and fuel characteristics, and operating conditions. The BSEP EPU operation includes changes in the reactor power level, power distribution (radial and axial), a different fuel design (GE14 instead of GE8X8), and an increased feedwater flow, all of which could affect the plant's instability response. The NRC staff evaluated the information that the licensee provided regarding the applicability of the key parameters assumed in the NEDO-32047-A analyses, the potential impact of differences that may exist, and whether any of the differences would impact the effectiveness of the required operator actions. In a RAI response, the licensee compared the EPU operating parameters for BSEP Units 1 and 2 to the key input parameters assumed in the generic ATWS instability studies. The licensee stated that the key driving parameters and the EPU operating conditions for BSEP Units 1 and 2 are similar to the conditions assumed in the generic studies.

Since the ATWS instability studies in NEDO-32047-A and NEDO-32164 were based on GE8X8 fuel designs and full-power operating conditions, GENE performed ATWS instability sensitivity studies using the 10X10 GE14 fuel design at a more limiting full-power operating condition than will exist for the BSEP Units 1 and 2 EPU operating conditions, including higher rod line. On the basis of these studies, GENE reported that the ATWS instability studies show a fully coupled neutronic/thermal-hydraulic reactor power/flow response that is similar to the those reported in previous studies. Furthermore, since the GE14 fuel design has lower heat flux per rod than the GE8X8 fuel bundle designs, GENE stated that the GE14 fuel design is less susceptible to extended fuel rod dryout than previously reported in NEDO-32047A. The same conclusions are also applicable to the GE13 (i.e., 9X9 design). For an ATWS instability event without mitigation, GENE determined that it expects that at a more limiting condition than BSEP Units 1 and 2 EPU/MELLLA condition, the extent of fuel damage would be bounded by that reported in the NEDO-32047-A ATWS instability analyses.

From its review, the NRC staff determined that for BSEP Units 1 and 2, most key parameters that influence the ATWS instability response are comparable to the assumed conditions in the generic evaluations. For example, BSEP Units 1 and 2 initial power-to-core flow conditions (38.4 MW/Mlbm/hr), which affect the potential for instability is comparable to the 40.9 MW/Mlbm assumed in the NEDO-34047A instability response study. However, the axial power shape assumed in NEDO-32047A may not bound the expected axial power shape BSEP Units 1 and 2 for all exposures. However, GENE's subsequent sensitivity studies using the GE14 fuel design at more bounding operating conditions than the BSEP Units 1 and 2 EPU operation (e.g., higher rod line, power/flow condition, with GE 14 fuel), indicate that the GE14 fuel design stability performance offsets the impact of the EPU power distribution conditions. In addition, the effectiveness of the ATWS mitigation strategies to reduce the consequences of oscillations will not change with the EPU operation.

The NRC staff has reviewed the information provided and based on the results of the sensitivity studies reported by GENE for the GE14 equilibrium core and currently under NRC staff review, the NRC staff concludes that the consequences of an ATWS instability event for the BSEP Units 1 and 2 EPU operation remain bounded by the consequences documented in the generic topical report NEDO-32047-A.

12.7 Audit Conclusions

The NRC staff performed an on-site review of the areas where CP&L deviated from the ELTR1 guidelines- ECCS-LOCA, stability setpoint calculations and the transient analyses. The NRC staff's audit also included the Brunswick EPU core design, fuel design and thermal limits assessment, implementation of the long-term stability Option III and system performance evaluation. The RAIs generated during the audit and the corresponding licensee's responses document any information obtained in the audit that was used in the NRC staff's finding. These documents provided a valuable means to augment the summarized results and conclusions provided in the PUSAR. Information obtained from the task reports that were used to make the NRC staff's finding were subsequently documented in a RAI. The NRC staff concluded that the on-site review did not result in any open issues and any inadequacies determined during the audit were resolved during the review process and are discussed in the applicable sections of this document.

13.0 STATE CONSULTATION

In accordance with the Commission's regulations, the North Carolina State official was notified of the proposed issuance of the amendment. The State official had no comments.

14.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on April 4, 2002 (67 FR 16132). The draft Environmental Assessment provided a 30-day opportunity for public comment. No comments were received on the draft Environmental Assessment. The final Environmental Assessment was published in the *Federal Register* on May 22, 2002 (67 FR 36040). Accordingly, based upon the Environmental Assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

15.0 CONCLUSION

The NRC staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

16.0 REFERENCES

1. General Electric Nuclear Energy, "Safety Analysis Report for Brunswick Units 1 and 2 Extended Power Uprate," NEDC-33039P, (DRF A22-00113-53), August 2001.

2. Letter from John S. Keenan, Carolina Power & Light Company, to Nuclear Regulatory Commission, "Request for License Amendments Extended Power Uprate" August 9, 2002.

3. Letter from John S. Keenan, Carolina Power & Light Company, to Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Request For License Amendments – Extended Power Uprate (NRC TAC NOS, MB2700 and MB2701)," March 4, 2002.

4. Letter from John S. Keenan, Carolina Power & Light Company, to Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Request For License Amendments – Extended Power Uprate (NRC TAC NOS, MB2700 and MB2701)," March 12, 2002.

5. GE Report NEDC-33039P, "Safety Analysis Report for Brunswick Units 1 and 2 Extended Power Uprate - Errata and Addenda," E&A Number 1, November 28, 2001 (Proprietary).

6. Carolina Power & Light Company, "Updated Final Safety Analysis Report," Brunswick Steam Electric Plant, Units 1 and 2.

7. General Electric Energy, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Report NEDC-32424P-A, (ELTR1), February 1999.

8. General Electric Energy, "General Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Report NEDC-32523P-A (ELTR2), February 2000.

9. General Electric Energy, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate - Supplement 1, Volume 2," Licensing Topical Report NEDC-32523P-A, Suppl 1, (Suppl.1 to ELTR2), February 1999.

10. General Electric, "General Electric Standard Application for Reactor Fuel," GESTAR II, NEDE-24011-P-A.

11. General Electric Nuclear Energy, "BWR Owners' Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology And Reload Applications," Licensing Topical Report NEDO-32465, May 1995.

12. General Electric Nuclear Energy, "ATWS Rule Issues Relative to BWR Core Thermal-Hydraulic Stability," NEDO-32047-A, June 1995.

13. General Electric Nuclear Energy, "BWR Owners Group Long-term Stability Solution Licensing Methodology," NEDO-31960-A and Supplement 1, April 1996.

14. General Electric, "Assessment of BWR Mitigation of ATWS, Volume II," (NUREG 0460 Alternative No. 3), NEDE-24222, December 1979.

15. Nuclear Regulatory Commission, “Power Oscillation in Boiling Water Reactors (BWRs),” Bulletin Number 88-07, Supplement 1, December 1988.

16. Nuclear Regulatory Commission, “Standard Review Plan,” NUREG-0800, April 1996.

ATTACHMENT: List of Acronyms

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LIST OF ACRONYMS

AC - alternating current
ACP - activated corrosion products
ADS - automatic depressurization system
ALARA - as low as reasonably achievable
AOO - anticipated operational occurrence
AOP - abnormal operating procedure
APRM - average power range monitor
ART - adjusted reference temperature
ASME - American Society of Mechanical Engineers
AST - alternative source term
ATWS - anticipated transient without scram
AV - allowable value
BOP - balance-of-plant
BSEP - Brunswick Steam Electric Plant
BTS - Brunswick Training Section
BWR - boiling water reactor
BWROG - Boiling Water Reactor Owners Group
BWRVIP - Boiling Water Reactor Vessel and Internals Project
CAD - containment atmospheric dilution
CBP - condensate booster pump
CDF - core damage frequency
COLR - core operating limits report
CP&L - Carolina Power & Light Company
CP - condensate pump
CRD - control rod drive
CRDA - control rod drop accident
CRDM - control rod drive mechanism
CREVS - control room emergency ventilation system
CRTP - current rated thermal power
CS - core spray
CSC - containment spray cooling
CST - condensate storage tank
CUF - cumulative usage factor
CWIP - circulating water intake pump
DBA - design-basis accident
DC - direct current
DGVR - degraded grid voltage relays
DHR - decay heat removal
DIVOM - delta critical power ratio over initial critical power ratio versus oscillation magnitude
ECCS - emergency core cooling system
EFPY - effective full-power years
EOP - emergency operating procedure
EPRI - Electric Power Research Institute
EPU - extended power uprate
FAC - flow-accelerated corrosion
FIV - flow-induced vibration
FIVE - fire-induced vulnerability evaluation
F-V - Fussell-Vesely

GDC - general design criteria
GE- General Electric Company
GENE - General Electric Nuclear Energy
GL - Generic Letter
HCLPF - high confidence of a low probability of failure
HCU - hydraulic control unit
HELB - high-energy line break
HEP - human error probability
HFO - high winds, floods, and other
HPCI - high-pressure coolant injection
HRA - human reliability analysis
HVAC - heating, ventilation, and air conditioning
ICA - interim corrective action
ICF - increased core flow
IN - Information Notice
IPE - individual plant examination
IPEEE - individual plant examination of external events
LERF - large early release frequency
LCO - limiting condition for operation
LOCA - loss-of-coolant accident
LHGR - linear heat generation rate
LOFW - loss-of-feedwater
LOOP - loss of offsite power
LPCI - low pressure coolant injection
LTR - licensing topical report
MAAP - modular accident analysis program
MAPLHGR - maximum average planar linear heat generation rate
MCPR - minimum critical power ratio
MCRACS - main control room atmosphere control system
MELLLA - maximum extended load limit line analysis
MOV - motor-operated valve
MSIV - main steam isolation valve
MSIVD - main steam isolation valve closure-direct
MWe - megawatts electric
MWt - megawatts thermal
NEI - Nuclear Energy Institute
NPSH - net positive suction head
NRC - U.S. Nuclear Regulatory Commission
NSSS - nuclear steam supply system
OLMCPR - operating limit minimum critical power ratio
OPRM - oscillation power range monitor
ORTP - original rated thermal power
PCT - peak cladding temperature
PRA - probabilistic risk assessment
PRDF - pressure regulator downscale failure
PRFO - pressure regulator failure to open
PRNM - power range neutron monitoring
PSA - probabilistic safety assessment
PSS - power system stabilizers

P-T - pressure-temperature
PUSAR - Safety Analysis Report for Brunswick Units 1 and 2 Extended Power Uprate
RAI - request for additional information
RCIC - reactor core isolation cooling
RCPB - reactor coolant pressure boundary
RCS - reactor coolant system
RG - Regulatory Guide
RHR - residual heat removal
RIPD - reactor internal pressure difference
RLE - review level earthquake
RPS - reactor protection system
RPV - reactor pressure vessel
RSLB - recirculation suction line break
RTP - rated thermal power
RWCU - reactor water cleanup
SAFDL - specified acceptable fuel design limit
SAT - startup auxiliary transformers
SBO - station blackout
SDC - shutdown cooling
SE - safety evaluation
SER - safety evaluation report
SFP - spent fuel pool
SFPCC - spent fuel pool cooling and cleanup
SGTS - standby gas treatment system
SLC - standby liquid control
SLMCPR - safety limit minimum critical power ratio
SLO - single recirculation loop operation
SMA - seismic margins assessment
SPC - suppression pool cooling
SPDS - safety parameter display system
SSFPC - supplemental spent fuel pool cooling
SR - surveillance requirement
SRP - Standard Review Plan
SRV - safety/relief valve
SRVDL - safety/relief valve discharge line
TAF - top-of-active fuel
TBCCW - turbine building closed cooling water
TCV - turbine control valve
TEDE - total effective dose equivalent
TLO - two recirculation loop operation
TS - technical specification(s)
TSV - turbine stop valve
UAT - unit auxiliary transformer
UFSAR - Updated Final Safety Analysis Report
UHS - ultimate heat sink
USAS - United States of America Standards
USE - upper shelf energy